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to produce chemicals

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Accelerating the transition to
RENEWABLE FUELS

SPECIAL FOCUS: PLANT SAFETY AND ENVIRONMENT

BIOFUELS, ALTERNATIVE/RENEWABLE FUELS

CATALYSTS

MAINTENANCE AND RELIABILITY

DIGITAL TECHNOLOGIES

DIGITAL EXCLUSIVES

DEPARTMENTS

COLUMNS

WEB EXCLUSIVE

Cover Image: View of Ampol's Lytton refinery in Brisbane, Australia. Ampol has initiated the Future Fuels Desulfurization Project, which will enable the refinery to produce Euro-6 fuels by 2025. Photo courtesy of Ampol.

HP Industry Perspectives

Hydrocarbon Processing to announce winners of sixth annual *HP* Awards

On October 12, *Hydrocarbon Processing* will be announcing the winners of the 2022 *HP* Awards. The live, in-person, black tie event will be held at the Houstonian Hotel, Club and Spa in Houston, Texas. The *HP* Awards honor the hydrocarbon processing industry's (HPI's) leading innovations, technologies and services, as well as outstanding personal contributions to the industry over the past year. These benefits to the HPI are making operations safer, more efficient and more profitable. *Hydrocarbon Processing* wishes to recognize and celebrate the achievements these individuals and companies have brought to the global processing industries.

The 2022 *HP* Awards comprise 16 strategic categories (13 technical/services and three people-focused awards). More than 100 nominations were submitted from numerous countries around the world. Each abstract was voted on by an independent *Hydrocarbon Processing* advisory board.

The following is a list of the award categories:

- Best AR/VR/AI Technology
- Best Asset Monitoring Technology
- Best Asset Reliability/Optimization Technology
- Best Automation Technology
- Best Catalyst Technology
- Best Digitalization Technology
- Best Gas Processing/LNG Technology
- Executive of the Year
- Best Health, Safety or Environmental Contribution
- Best Instrument Technology
- Best Modeling Technology
- Best Petrochemical Technology
- Best Refining Technology
- Sustainability
- Licensor of the Year
- Most Promising Engineer
- Lifetime Achievement.

A complete list of nominees in each category are listed on the *Hydrocarbon Processing* website: www.HydrocarbonProcessing.com/awards. Visitors to the site can also register for the event, as well as find more information on sponsorship opportunities.

For those unable to attend the *HP* Awards gala, *Hydrocarbon Processing* will be live tweeting the winners on *Hydrocarbon Processing's* Twitter account and other social media platforms (Facebook and LinkedIn). The complete list of winners will be posted on the *Hydrocarbon Processing* website on Thursday, October 13, as well as featured in the publication's e-newsletter.

For more information regarding the sixth annual *HP* Awards, visit www.HydrocarbonProcessing.com/awards. For more information on sponsorship opportunities, contact Melissa Smith, Global Events Director, at Melissa.Smith@GulfEnergyInfo.com. HP

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SUBSCRIPTIONS

Subscription price (includes both print and digital versions): One year $399, two years $679, three years $897. Airmail rate outside North America $175 additional a year. Single copies $35, prepaid.

Hydrocarbon Processing's Full Data Access subscription plan is priced at $1,995. This plan provides full access to all information and data *Hydrocarbon Processing* has to offer. It includes a print or digital version of the magazine, as well as full access to all posted articles (current and archived), process handbooks, the *HPI Market Data* book, Construction Boxscore Database project updates and more.

Because *Hydrocarbon Processing* is edited specifically to be of greatest value to people working in this specialized business, subscriptions are restricted to those engaged in the hydrocarbon processing industry, or service and supply company personnel connected thereto.

Hydrocarbon Processing is indexed by Applied Science & Technology Index, by Chemical Abstracts and by Engineering Index Inc. Microfilm copies available through University Microfilms, International, Ann Arbor, Mich. The full text of *Hydrocarbon Processing* is also available in electronic versions of the Business Periodicals Index.

DISTRIBUTION OF ARTICLES

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Hydrocarbon Processing (ISSN 0018-8190) is published monthly by Gulf Energy Information, 2 Greenway Plaza, Suite 1020, Houston, Texas 77046. Periodicals postage paid at Houston, Texas, and at additional mailing office. POSTMASTER: Send address changes to Hydrocarbon Processing, P.O. Box 2608, Houston, Texas 77252.

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Publication Agreement Number 40034765 Printed in USA

Other Gulf Energy Information titles include: *Gas Processing™*, *H2Tech*, *Petroleum Economist©*, *World Oil®*, *Pipeline & Gas Journal* and *Underground Construction*.

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Announcing the nominees for the 2022 Top Projects awards

Since the mid-2010s, *Hydrocarbon Processing* has recognized the top refining and petrochemical projects of the year. These capital investments have significantly contributed to the expansion of the hydrocarbon processing industry and have been instrumental in providing new refined and petrochemical products to traditional and emerging markets.

Using Gulf Energy Information's Global Energy Infrastructure database, the editors of *Hydrocarbon Processing* have selected 10 nominees for the 2022 Top Projects awards. These capital investments can join a prestigious list of past winners, including:

Refining:

- 2021: BAPCO modernization program (Bahrain)
- 2020: Visakh refinery modernization (India)
- 2019: Kochi integrated refinery expansion project (India)
- 2018: Jazan refinery (Saudi Arabia)
- 2017: KNPC's Al-Zour refinery (Kuwait)
- 2016: KNPC's Clean Fuels Project (Kuwait)

Petrochemicals:

- 2021: Gulf Coast Growth Ventures' ethane cracking and derivatives project (U.S.)
- 2020: LIWA Plastics Industries complex (Oman)
- 2019: Shell's Pennsylvania petrochemicals complex (U.S.)
- 2018: ZapSibNeftekhim (ZapSib-2) petrochemicals complex (Russia)
- 2017: Petronas' Pengerang Integrated complex (Singapore)
- 2016: Dow Chemical's Oyster Creek PDH project (U.S.).

This year's nominees (**TABLES 1** and **2**) represent nearly $50 B in capital investments, more than 600,000 bpd in new refining capacity and more than 11 MMtpy in additional petrochemicals production.

Beginning October 1, readers can make their voices heard in an exclusive online poll at www.HydrocarbonProcessing.com. The winners will be revealed in *Hydrocarbon Processing's* December issue. HP

TABLE 1. Top refining project nominees

Operator	Project	Location
ExxonMobil	Beaumont Light Atmospheric Distillation Expansion (BLADE)	U.S.
Indian Oil Corp. Ltd.	Barauni refinery (BR9) expansion project	India
Neste	Singapore biofuels/SAF plant	Singapore
OQ8	Duqm refinery expansion	Oman
Uzbekistan GTL	UzGTL complex	Uzbekistan

TABLE 2. Top petrochemicals project nominees

Operator	Project	Location
Inter Pipeline	Heartland petrochemicals project	Canada
Jiangsu Shenghong	Lianyungang refinery and petrochemicals integrated complex	China
LyondellBasell	PO/TBA project	U.S.
PetroChina	Jieyang refinery and petrochemicals integrated complex	China
Siam Cement Group	Long Son petrochemicals complex	Vietnam

INSIDE THIS ISSUE

S. KULKARNI, Allied Market Research

Innovative approaches to manufacture base oils gain customers' attention

For years, lubricating greases and motor oils have been manufactured from base oils. Lubricating greases and other automotive oils require different properties in oil and different compositions—the most crucial factor is the viscosity of the liquid at different temperatures. Moreover, the concentration of base oil molecules and how easily they are extracted determine whether the crude oil is suitable to be made into a base oil. The crude oil is heated and (by refining it) the base oil is manufactured. This process makes light hydrocarbons to produce petrol and other fuels, whereas heavy hydrocarbons are used to produce bitumen and base oils.

One widely known base oil is paraffinic crude oil. However, some naphthenic crude oils develop products that have better solubility and show some valuable properties at low temperatures.

According to the author's company, the global base oil market is expected to reach $41.7 B by 2030, growing at a compound annual growth rate (CAGR) of 1.8% from 2021 to 2030. Increases in demand for high-grade oils in the automotive industry and stringent environmental legislations are the prime factors that drive the market.

As per the report, the Asia-Pacific region contributed the largest share of the market in 2020 and will continue to grow at the highest CAGR in the coming years. Due to the growing rate of motorization in the developing countries in the region (e.g., China and India), the demand for lubricants is expected to rise. Furthermore, strict environmental legislation that emphasizes meeting performance standards will help the base oil market grow in the Asia-Pacific region.

Evolution of lubrication technology and base oils. Year after year, lubrication technology continues to improve. Solvent-refining technology was replaced by hydroprocessing technologies, which allowed the manufacture of various base oils. The hydroisomerization process has gained attention, as it produces very high-quality base oil. These hydroisomerization technologies are now widely accepted and adopted around the globe and have created an abundant supply of base oils that show excellent low-temperature performance and stability.

Over time, polyalphaolefins (PAOs) have shown superior performance characteristics, including volatility, pour point, viscosity index and oxidation stability, unlike any other conventional mineral oils. Additionally, with the use of modern base oil manufacturing, pour point, viscosity index, oxidation stability and volatility can be controlled independently. Based on these properties, various base oils can be differentiated and used for different purposes.

The current trend in the base oil industry is toward manufacturing base oils and lubricants with higher purity, longer life and lower volatility. The demand for base oils with higher lubrication performance has increased, as they offer better hydroprocessing catalysts, process improvement and feedstock.

One of the prime base oil feedstocks is natural gas. Over the last few decades, the industry has witnessed the advent of a new ultra-performance base oil that is derived from wax, which in turn is derived from natural gas. This base oil has higher PAOs than conventional base oils and can be used to make long-life, fuel-efficient automotive and industrial oils.

While conventional methods of manufacturing base oils have proven to be effective, several market players have introduced competing technologies that can maintain and improve the quality of traditional synthetic oils. New and improved base oils will help automotive and equipment manufacturers meet industry standards and the demand for cleaner, better lubricants.

As base oil technology evolves, customers will gain improved protection of automobiles and expensive machinery, including turbines. The performance of lubricants affects almost all industries globally and base oil development will open new market opportunities.

Market development and the launch of new base oils. As the demand for base oils has increased significantly in the automotive industry, several companies have launched novel base oils derived from innovative resources and using state-of-the-art technologies.

For instance, Nynas AB, a leading manufacturer of specialty naphthenic oils and bitumen products, launched a highly refined base oil[a] with an optimized viscosity index for maximum cooling and better ability to blend with other base oils. According to the company, the low-temperature performance of the base oil is better than existing products at similar viscosity. Moreover, it has been carefully developed to meet the ever-increasing demand for a grade with a high naphthenic character. The company says its base oil has enough versatility to perform in stable emulsions and in different lubricant applications. It has high naphthenic, carbon type content as well as suitable aniline point, and can serve as an ideal fit in metalworking fluids formations, including emulsion coolants and industrial lubricant applications.

Similarly, Croda Intl. Plc, a UK-based leading specialty chemical company, launched a new dielectric ester base oil for electric vehicle (EV) transmission

fluids and battery cooling to enhance stability, performance and safety. The demand for next-generation fluids that can offer effective thermal management and compatibility has increased. The researchers' study has demonstrated the improved vehicle performance with the use of ester base oil.

The global base oil market is expected to reach $41.7 B by 2030, growing at a CAGR of 1.8% from 2021 to 2030.

Unfortunately, the ever-increasing demand for base oils has taken a toll on the environment. The overuse and reservoir depletion of fossil fuels and natural gas have encouraged companies to look for other ways to manufacture base oils.

Recently, ADNOC Distribution, the largest fuel and convenience retailer in the United Arab Emirates, has launched a series of lubricant products[b] for diesel and petrol engines that are manufactured from 100% plant-based base oil. The newly launched products are a part of an initiative to expand the company's sustainable and eco-friendly product range. Two base oils[c,d] are manufactured for petrol engines and diesel engines, respectively, with the use of high-quality blending technology. These products are made from plant-based base oils to meet market demand for eco-friendly product options.

Base oils are derived from sustainable sources, including soy, palm, rapeseed and coconut. This product range is formulated to deliver improved engine performance compared to existing synthetic base oils owing to their one-of-a-kind molecular composition.

Lubricating base oils have high-boiling, high-viscosity, higher-molecular weight and refined crude oil products. The advent of gas-to-liquids (GTL) and all-hydroprocessing routes to produce base oils of higher quality have opened new opportunities in the market.

Over the last few years, new refinery processes have developed significantly and market players have launched plant-based base oils to meet the sustainability goals of both consumers and manufacturers. HP

NOTES

[a] NYBAS BT 22
[b] Voyager Green Series
[c] Voyager PX Green
[d] Voyager DX Green

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HP Innovations

Portable flowmeter for on-demand pipe flow measurement

AW-Lake now offers a new Portable Transit Time Ultrasonic Flow Meter (FIG. 1) in addition to the full-sized clamp-on version that provides non-contacting flow measurement for the most challenging industrial environments with minimal installation complexity and costs. The new portable ultrasonic meter was designed to be deployed easily to measure flow on-demand, without difficult installations or process interruptions.

The hand-held unit is encased in a rugged IP67 housing and works with the same three interchangeable transducers as the full-sized meter, which makes it suitable for measurements on a wide range of metal and plastic pipe materials on pipes with diameters from 0.5 in.–48 in. A simple menu allows for fast and easy programming of pipe diameter, pipe material, liquid types and measurement units. In addition to providing a standard 4-20mA/0-5V analog output, optional Modbus RTU and HART communications provide instantaneous flowrate, volume, total, run hours and diagnostic information.

An intuitive on-screen user interface with a data logger enables operators to view flow reports or download logs for use in other programs, and it features data management storage of 12.5 MM data points with logger software for data viewing and reporting. Through the use of an integrated USB-C port, the PTFM 6.1 seamlessly expands its input and output capability to meet future requirements without replacing the whole meter.

The flowmeters use the transit time ultrasonic principle of measurement that works by measuring the flight difference for ultrasonic sound pulses transmitted from one transducer to another. The time between transmitted and received signals is precisely measured by the flowmeters. Both ultrasonic flowmeters are ideal for measuring the flowrate of clean, non-aerated fluids in full pipes such as water, chemicals and fuel oils with highly accurate and reliable flow measurement.

Automatic heavy-duty pressure switch

WIKA India (a wholly owned subsidiary of WIKA Global) has recently launched the PSM-630, an automatic heavy-duty pressure switch for applications like air compressor and water pumps. The model PSM-630 (FIG. 2) can also be used in industrial control, monitoring and alarm applications. The switch point is engineered so it can be manually adjusted onsite and is also adjustable for automatic cut-off within the prescribed range. An entire electrical system can be controlled by the pressure switch to maintain the pressure of the storage unit.

The instrument can switch electrical loads of up to AC 440 V, 16 A. The integrated relief valve (option) is used for depressurizing the pressure chamber of the compression piston before starting the compressor. With the manual on/off knob, the contact system can be locked in the open position, regardless of the process pressure. This helps to maintain the safety of the machine and workplace.

The PSM-630 has an integrated relief valve to ensure smooth restart of the compressor. This adds to the safety measures provided by the manual knob on the top, which is easily accessible by the customers. Among the other safety measure, the switch cannot be easily tampered with as the process connection is done through forging or casting. The switch has a snap action mechanism built into it—it stops automatically once the pressure reaches the defined particulars, causing no side effects to the machine itself. Also, the single process connection is threaded in four different ways to accommodate safety valve and other type of switches

Predict and avoid incidents with AI

Digital Energy has released ODIN Safety, a health, safety and environment (HSE) application that predicts and avoids incidents using artificial intelligence (AI). ODIN Safety provides industrial sites with an immediate impact on safer operations by leveraging AI and digital twin technology. With Digital Energy's unique HSE knowledge library and AI-powered predictive HSE, organizations can quickly access predictive safety insights augmented by the Bentley iTwin platform. ODIN Safety provides leading indicators and real-time digital advisory for risk assessments, permitting and other key forms. With ODIN Safety

FIG. 1. The AW-Lake Portable Transit Time Ultrasonic Flow Meter.

FIG. 2. WIKA India has launched its PSM-630 automatic heavy-duty pressure switch.

data and insights visualized with iTwin technology, any team or manager can easily and quickly assess relevant activities and key areas of focus for a given period while minimizing any key messages potentially lost during a shift handover or during a toolbox talk.

Operations control software

AVEVA has launched the 2023 release of its operations control software, the first major coordinated release of its HMI/SCADA software portfolio, available in both perpetual and subscription purchases. The new release further supports the delivery of AVEVA Operations Control, a flexible, subscription-based solution of integrated capabilities that promotes greater efficiency and workforce collaboration at the scale that best suits the business.

AVEVA Operations Control simplifies day-to-day routines of teams by aligning workers around common digital threads of information, delivering the data and insights they need to drive growth at every level through increased efficiency, agility and reliability. With rich visualization technologies, analytics and development tools deployed within a hybrid cloud and on-premises environment, customers can ensure performance consistency, remove opportunity for human error, and improve operator insight and reactions to process deviations. Not only can critical information be retrieved faster, but inbuilt flexibility provides greater scaling of data, users or routes to revealing the correct decision.

The 2023 operations control release focuses on worker empowerment with UI/UX enhancements, increased flexibility for web and mobile users, and greater connectivity. This release consists of updates in the following offerings: AVEVA System Platform 2023, AVEVA InTouch HMI 2023, AVEVA Edge 2023, AVEVA Plant SCADA 2023, AVEVA Historian 2023, AVEVA Communication Drivers 2023, AVEVA Reports for Operations 2023, AVEVA Development Studio and AVEVA Teamwork.

The 2023 operations control software release is available through several procurement methods, including AVEVA Flex, the advanced industrial software subscription program. Customers can choose individual software offers within the operations control portfolio or realize new transformational value with end-to-end visibility across operations by subscribing to AVEVA's broad portfolio through AVEVA Operations Control. AVEVA Operations Control removes traditional limitations on implementation by including unlimited software usage (measured by the number of users) and offering maximum commercial flexibility.

AVEVA Operations Control helps workers to do their jobs in a more sustainable way. Its comprehensive digital framework supports quicker, data-backed responses to events that require resolution, providing reliable process management systems and reducing the effort required to train new staff. Customers across industries can further enrich their approach to environmental, social and governance (ESG) initiatives by leveraging the solution to tap data-driven insights for more efficient and environmentally sustainable operations.

FIG. 3. Inpro/Seal has introduced a new magnetic bearing isolator: VBMag.

Bearing protection in flooded and mist applications

Inpro/Seal has introduced a new magnetic bearing isolator: VBMag. Utilizing magnetically energized faces to create a liquid-tight seal, VBMag (**FIG. 3**) protects against lubrication loss and contamination ingress in challenging applications, such as flooded, high oil splash, or oil mist lubrication environments. With VBMag, there is zero shaft wear, making it an ideal choice for applications that historically used elastomeric lip seals, which can wear quickly at the point of contact and damage the shaft. VBMag delivers long-term performance and reduces the need for unscheduled downtime and maintenance costs.

VBMag bearing isolators are IP66 rated to meet high industry standards for bearing protection. Precision-lapped faces energized by rare earth magnets create a liquid-tight seal suitable for a wide variety of applications. The innovative design allows the maximum amount of lubrication to reach the faces, which provides optimum conditions for a long sealing life.

Hydrocarbon passive fire protection of downstream assets

In oil and gas facilities, fires can be disastrous—lives can be lost and damage costs can run into the millions of dollars. Hempel has launched its first product for the hydrocarbon passive fire protection (PFP) segment: Hempafire XTR 100. Providing UL 1709-certified hydrocarbon PFP in a lightweight coating with low dry film thicknesses, Hempafire XTR 100 offers significant safety and project benefits and reduces application time and overall project costs for asset owners, operators and applicators.

An epoxy intumescent coating, Hempafire XTR 100 insulates steel during a hydrocarbon pool fire, extending the steel's load-bearing capacity for up to 4 hr, allowing more time for the safe evacuation of personnel and protection of valuable assets and equipment while fire-fighting teams extinguish the fire. The coating is designed specifically for the oil and gas segment, such as downstream refining and petrochemical plants.

Hempafire XTR 100 lowers the total applied weight per square meter, bringing additional benefits by making transportation and construction easier and lowering overall project costs. To simplify project complexity for customers, Hempafire XTR 100 can be applied to both stick-build and modular constructions, and it only requires mesh reinforcement around section flanges. It also aids high productivity: a 2-hr Hempafire XTR 100 system can be applied in one working day and the coated sections can be moved the next day. This enables applicators to increase productivity, especially when applying the product in-shop.

Actionable insights to eliminate data gaps and achieve optimum plant performance

GE Digital has released a software solution combining Performance Intelligence™ with APM Reliability™ designed to form a performance advisory solution combining real-time thermal performance data and analysis software with the power of analytics for strategic and data-driven decision-making. Integrating the two provides a highly flexible, easy to use problem-solving solution to maintain a thermal power generation plant or fleet at optimal efficiency.

In response to factors including ways to lower emissions, fluctuating fuel prices, stagnant power prices and escalating operating costs, plant operations teams are being charged to act with greater speed and efficiency to maintain their assets' economic expectation. Performance Intelligence integrates with APM Reliability to help plant personnel gain visibility to equipment health, assess and identify degradation and reliability issues, understand the impact to plant capability and financial performance, and empower teams to act with greater speed and efficiency.

The solution incorporates the power of 340+ GE and non-GE Digital Twin Blueprints from SmartSignal™ predictive analytics software, the analytics engine behind GE Digital's Predictive Maintenance solutions. Combined with Performance Intelligence with Reliability, the solution is designed to enable fuel savings, productivity and risk reduction.

Performance Intelligence with APM Reliability is designed to help deliver a holistic problem-solving solution to maintain the plant at optimal efficiency with:

- Advanced thermal modeling across the entire load range with actionable recommendations
- Analytics covering the entire operating range of assets with actionable recommendations
- Fully integrated data streams into the work management process
- New analytics for economic predictions and "what-if" simulations.

Fire and gas system

Process and safety engineers who require a full-featured fire and gas system with built-in cloud-ready capabilities will find the advanced, next-gen HazardWatch FX-12 fire and gas system from MSA Safety delivers peace-of-mind and security when it comes to reliable plant safety monitoring.

Developed with MSA's detection and systems integration expertise, as well as the process control/automation proficiency of Rockwell Automation, the HazardWatch FX-12 system is a powerful and flexible total safety solution designed to protect people, equipment, facilities and nearby communities. Designed for use in hazardous industries, the system is ideal for oil/gas production and tanker loading/unloading, petrochemical refining and storage, pipelines and gas compressor stations, LNG facilities, CNG and hydrogen (H_2) production and vehicle terminals, electric power generation, aircraft maintenance facilities, aerospace launch sites, automotive and pharmaceutical manufacturing.

The HazardWatch FX-12 system (FIG. 4) is designed with Rockwell Automation's industry proven Allen-Bradley ControlLogix™ programmable logic controller (PLC) technology and MSA's advanced gas and flame detection field devices. Allen-Bradley DLR-enabled communication protocols allow secure integration with other Rockwell products. Offering intelligence, flexibility and reliability, the system's controller hardware configuration and software have been tested by Factory Mutual to verify NFPA 72 (2013) compliance.

The system includes: a stand-alone local fire and gas alarm panel with touch screen operator interface; a redundant power supply to support the fire and gas system per NFPA 72; easy integration with third-party auxiliary devices such as horns, beacons and fire suppression systems; and FM-approved Ethernet/IP system communications to DCS or ESD Systems, with optional Modbus. The HazardWatch FX-12 can accommodate up to 12 field devices per alarm panel, with the capability to network up to 12 panels. The panel is wall mounted in a NEMA 12 rated enclosure. User connections are made at a rail mounted "swing link" with terminal blocks organized by input/output type. The PLC processor and the touchscreen are fitted with non-volatile memory.

Highly versatile to support the full range of fire, flame and gas detection needs, the HazardWatch FX-12 is compatible with the industry's leading flame and gas sensing technologies from MSA. The flame detector models available include the General Monitors Multi-Spectral Infrared (MSIR) FL4000H, the UV/IR Optical FL500 and others.

FIG. 4. MSA Safety's next-gen HazardWatch FX-12 fire and gas system.

For combustible or toxic gas and oxygen deficiency (O_2) monitoring, the HazardWatch FX-12 supports the Ultima® X5000 and General Monitors S5000 gas detectors. In addition, for tank or pipe leak monitoring, the Observer®i ultrasonic gas leak (UGLD) detector is available, and for plant or area perimeter monitoring the IR5500 or Senscient ELDS open path gas detectors are supported.

For safety monitoring onsite or in the cloud, the HazardWatch FX-12's optional FieldServer Gateway supports sharing critical operational data 24/7 via BACnet, Ethernet/IP, Modbus, SNMP, and a host of other protocols. MSA's remote monitoring and notification solutions help support fire alarm panels and the HazardWatch FX-12 fire and gas system by notifying the SCADA system of events in the field.

Software optimizes refining and petrochemical operations

KBC (A Yokogawa Company) has released a new version of its award-winning Petro-SIM® process simulation software. Version 7.3 now has a more reliable and robust reactor for modeling bio-oils and an emissions calculation model for gas turbines and burners. As operators tran-

sition to clean energy, they now have access to highly accurate methods to design, monitor and streamline operations while improving margins. Petro-SIM 7.3 technology lays the foundation for AI-based automated model maintenance, supporting the first of a series of applications that will deploy throughout 2H 2022.

Many countries are transitioning towards cleaner energy sources and optimizing energy consumption to reduce carbon emissions. The result is stringent environmental regulations that process industries must follow, which squeeze their already tight margins. The Petro-SIM 7.3 simulation tool has broadened its decarbonization simulation capabilities to accurately depict decarbonization processes, making it a scalable solution that helps operators overcome these challenges.

The technology integrates into daily work processes to deliver reliable predictions of combustion emissions, potential equipment failures and operational risks. Engineers can now go beyond traditional model building to optimizing operations, advancing performance monitoring, automating production scheduling, and analyzing and reducing emissions from combustion sources.

The petrochemical-polymer industry in particular is seeing a growing demand. However, the complexity of polymer processing makes it challenging for polymer manufacturers to develop and design process technologies to meet the necessary product quality. Petro-SIM 7.3 software with Predici-SIM technology can now simulate polymerization processes. This allows operators to evaluate and manage challenges so they develop and produce new polymer grades with desirable properties while optimizing key performance indicators and maintaining operating conditions in steady-state and dynamic modes for the entire petrochemical-polymer supply chain.

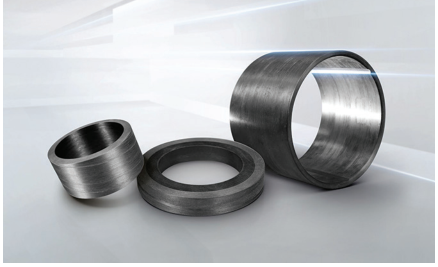

FIG. 5. Trelleborg Sealing Solutions' latest lightweight thermoplastic composite bearing, the HiMod® Advanced Composite Bearing Plus.

Lightweight thermoplastic composite bearing

Trelleborg Sealing Solutions has launched its latest lightweight thermoplastic composite bearing, the HiMod® Advanced Composite Bearing Plus, an enhanced dual-layer bearing with a low-friction modified PEEK layer that reduces friction and increases wear performance for use in bearing, wear ring and bushing applications.

Manufactured using Trelleborg's patented Automated Fiber Placement (AFP) technology, a thin low-friction liner is bonded to the inner diameters and can be added to the outer diameters of the bearing to create a high-quality solution for use in a wide range of industries. The HiMod Advanced Composite Bearing Plus (**FIG. 5**) will not seize or gall—unlike metal bearings—to reduce the likelihood of pump damage in chemical processing applications, has a low coefficient of friction, and can withstand extreme temperature ranges.

The addition of a low-friction layer within the HiMod Advanced Composite Bearing Plus provides up to 50% less sliding friction than with standard bearings, increasing performance and preventing damage to hardware components. These unique bearings can operate from an extremely low temperature of –156°C to > 274°C (–250°F to > 525°F) and are capable of continuous service even when wet, with nearly zero water absorption. Unlike other non-metal bearings, they do not crack or swell in extreme conditions, making them a reliable choice for a wide range of applications.

Trelleborg's AFP technology is part of a special continuous-fiber thermoplastic composite manufacturing process, which uses pre-impregnated unidirectional composite tapes to produce strong, lightweight composite bearings and other components. The manufacturing process utilizes In-Situ Consolidated (ISC) technology that requires no autoclave or other post processes to eliminate fiber wrinkling and offers an unlimited choice of fiber angles. Components are rapidly formed by a melt-bond process, which removes the need for adhesives, fasteners or welding. ISC technology enables the bonding of different materials, which can result in the creation of new, hybrid structures.

Compressor performance monitoring system

Elliott Group, a leading manufacturer of process compressors for oil and gas, petrochemical, liquefied gases and other industrial services, has rolled out its Gemini Compressor Performance Monitoring System. Developed jointly by Elliott Group and Tri-Sen Systems, Gemini is a focused software solution designed specifically for continuous monitoring, evaluation and analysis of critical compressor performance and associated auxiliary support systems, leading to improved operational control, better machine diagnostics, more functional review capabilities, and optimized compressor operation with increased plant reliability and efficiency.

Gemini is a package that successfully integrates rotor dynamics analysis, process data, high-fidelity compressor thermodynamic analysis, and nearly real-time visibility of key performance indicators into a single package that can be accessed from a smartphone, tablet or computer. The Gemini application includes: a custom Elliott compressor model (a digital twin) for evaluating compressor performance and performance changes; advanced vibration analysis with best-in-class vibration evaluation tools; and remote controls monitoring "HMI-twin" providing contextually relevant compressor and auxiliaries data through a responsive internet browser interface.

Accurate density measurement

A Dynatrol® CL-10-HY density cell and Series 2000 density digital converter can accurately measure the density of multiple fluids, including crude oil, diesel fuel, distillates, gasoline, ethane gas, isobutene, jet fuels and LPG. Dynatrol cells come in a full range of corrosion-resistant materials that are weather-tight and explosion proof, and serve broad temperature and pressure ratings. The Dynatrol cell is double-sealed for protection against leaks and provides density measurement for high-pressure service up to 1,480 psig. HP

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Achieve compliance with automated wastewater treatment for industrial facilities with cooling towers

Industrial facilities with cooling towers in the U.S. must meet U. S. Environmental Protection Agency (EPA) and local wastewater requirements for effluent, including those under the Clean Water Act. Failing to do so can result in severe fines that quickly escalate.

A wide range of industries utilize cooling towers in their facilities, such as metal processors and rubber, chemical and plastic product manufacturers. For industrial facilities with a cooling tower, a water treatment system is required to ensure an efficient process and long equipment life. If cooling tower water is not treated properly, fouling, scaling, corrosion and organic growth can trigger sizeable EPA and local environmental agency fines. This can not only cause facility downtime, but also reduce productivity and necessitate costly, premature equipment replacement.

A cooling tower water treatment system can consist of various technologies needed to regulate the level of alkalinity, chlorides, hardness, iron, organic matter, silica, sulfates, total dissolved solids (TDS) and total suspended solids (TSS). Although the type of industry and specific operational practices determine the type of wastewater generated, most involve suspended solids, heavy metals, organic compounds or a variety of other pollutants. Under the Clean Water Act, for example, the EPA has identified 65 pollutants and classes of pollutants as "toxic pollutants," of which 126 specific substances have been designated "priority" toxic pollutants.

For many plants utilizing cooling towers, this means installing a wastewater treatment system that effectively separates the contaminants from the water so it can be legally discharged into sewer systems or even re-used.

However, traditional wastewater treatment systems can be complex, often requiring multiple steps, a variety of chemicals and a considerable amount of labor. Even when the process is supposedly automated, too often technicians must still monitor the equipment in person. This usually requires oversight of mixing and separation, the adding of chemicals, and other tasks required to keep the process moving. Even then, the water produced can still fall below mandated requirements (**FIG. 1**).

Although paying to have industrial wastewater from a cooling tower hauled away is also an option, it is extraordinarily expensive. In contrast, it is much more cost effective to treat the industrial wastewater at its source, at or near the cooling tower. This can enable treated water to be reused, effluent to go into a sewer and treated sludge to pass a toxicity characteristics leaching procedure (TCLP) test, allowing disposal as non-hazardous waste in a local landfill.

FIG. 1. Untreated wastewater effluent.

Fortunately, complying with wastewater regulations has become much easier with more fully automated, wastewater treatment systems. Such systems not only reliably meet regulatory wastewater requirements, but also significantly reduce the cost of treatment, labor and disposal when the proper separating agents[a] are also used.

Cost-effective, automated wastewater treatment.

In contrast to labor-intensive, multiple-step processes, automated wastewater treatment can help to streamline production and cooling tower wastewater treatment—usually with a one-step process—while lowering costs at manufacturing facilities.

An automated wastewater treatment system for cooling towers can eliminate the need to monitor equipment in person while complying with mandated requirements. Such automated systems separate suspended solids, emulsified oil and heavy metals, and encapsulate the contaminants, producing an easily de-waterable sludge in minutes, according to production consultants at Sabo Industrial Corp., a New York, U.S.-based manufacturer, distributor and integrator of industrial waste treatment equipment and solutions, including batch and fully automated systems, separating agents[a], bag filters and accessories.

The water is typically then separated using a de-watering table or bag filters before it is discharged into sewer systems or further filtered for re-use as process water. Other options for de-watering include using a filter press or rotary drum vacuum. The resulting solids are non-leachable and considered non-hazardous, so they will pass all required testing.

These systems are available as manual batch processors, semi-automatic or automatic, and can be designed as a closed-

loop system for water reuse or provide a legally dischargeable effluent suitable for the sewer system. A new, fully customized system is not always required. In many cases, it can be faster and more cost-effective to add to or modify a facility's current wastewater treatment systems when this is feasible.

However, because every wastewater stream for cooling towers is unique to its industry and application, each wastewater treatment solution must be suited to or specifically tailored to the application. The first step in evaluating the potential cost savings and effectiveness of a new system is to sample the wastewater to determine its chemical make-up, followed by a full review of local water authority requirements and production consultants.

The volume of cooling tower wastewater that will be treated is also analyzed to determine if a batch unit or flow-through system is required. Other considerations include the size restrictions, so the system fits within the facility's available footprint.

Separating agents. Despite all the advances in automating wastewater treatment equipment, any such system for cooling towers requires effective separating agents that agglomerate with the solids in the wastewater so the solids can be safely and effectively separated out.

Due to the importance of separating agents for wastewater treatment, Sabo Industrial uses a special type of bentonite clay in a line of wastewater treatment chemicals[a]. This line of wastewater treatment chemicals is formulated to break oil and water emulsion, provide heavy metals removal, and promote flocculation, agglomeration and suspended solids removal.

Bentonite has a large specific surface area with a net negative charge that makes it a particularly effective adsorbent and ion exchange for wastewater treatment applications to remove organic pollutants, heavy metals, nutrients, etc. As such, bentonite is essential to effectively encapsulate the materials. This can usually be achieved in a one-step treatment, which lowers process and disposal costs.

In contrast, polymer-based products do not encapsulate the toxins, so systems that use that type of separating agent are more prone to having waste products leach back out over time or upon further agitation.

Today's automated systems, as well as the most-effective separating agents[a] can provide industrial facilities utilizing cooling towers with an easy, cost-effective alternative so they remain compliant with local ordinances. Although there is a cost to these systems, they do not require much attention and can easily be more economical than paying fines or hauling. HP

NOTES

[a] Cleartreat®

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Sustainable steel/chemicals production: Removal of impurities for valorization of steel mill gases

Industry faces significant challenges relating to the transition toward cleaner energy and more sustainable feedstocks. The key drivers of this transformation are greenhouse gas (GHG) avoidance and the formation of a more circular economy to lower the waste burden on the environment. Both transitions should support the needs of global population growth without affecting the planet's ability to also supply future generations. This is not the first transition that industry has faced, but, where previous industrial transitions were driven by technical developments (technology push), the current transitions are primarily driven by a strong societal pull. This means that the goals are clear, but the (technical) path to achieve these goals is not.

A traditional petrochemical value chain (**FIG. 1**) takes in carbon from fossil origin (oil or gas) and converts it into a broad variety of products in large assets that have been optimized for cost efficiency and product quality. This typically comes with a significant energy need that is traditionally delivered via combustion of fossil carbon, thus resulting in significant carbon dioxide (CO_2) emissions and a post-consumer waste disposal problem. Therefore, the challenge will be to develop technologies and partnerships to deliver circular processes that utilize renewable energy and feedstocks.

Today, most of the global steel production is produced using blast furnace technology (**FIG. 2**). In this route, iron ore is reduced with coke from coal in a blast furnace, followed by the removal of residual-free carbon in the steel by oxygen injection in an oxygen converter. In this process, three major gas streams are co-produced with the target product steel: coke oven gas (COG), blast furnace gas (BFG) and basic oxygen furnace gas (BOFG).

TABLE 1. Typical gas compositions for BFG, BOFG and COG. These gases are always saturated with water.[1]

	BFG	BOFG	COG
H_2, vol%	3–4	4	55–66
CO, vol%	20–25	58–65	6–8
CO_2, vol%	21–24	17–20	2–3
N_2, vol%	48–55	14–18	2–10
Oxygen (O_2), vol%	0.5	0.5	–
Methane (CH_4), vol%	–	–	20–26
$C_2 + C_3$, vol%	–	–	1–3

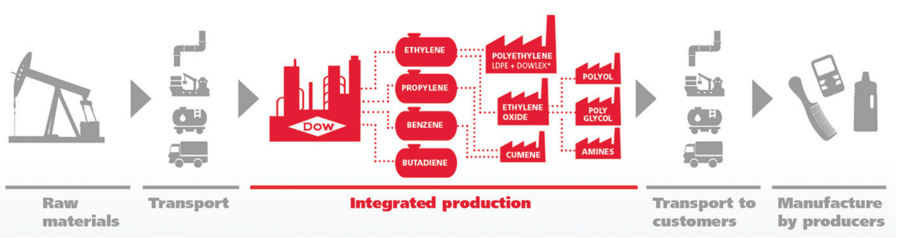

FIG. 1. Schematic representation of the carbon value chain for a petrochemical company.

A typical composition of these gases is represented in **TABLE 1,** which shows that COG primarily contains hydrogen (H_2) and light hydrocarbons, whereas the BOFG is carbon monoxide (CO) rich.[1] The largest amount of gas produced in a steel mill is BFG, which has a 1:1 ratio of CO and CO_2 in a matrix of ~50% nitrogen (N_2). This gas is very abundant in steel mills and is typically combusted in a power plant to produce electricity with a very high CO_2 footprint.[2] To create a greener electricity grid, an alternate use for CO is required. This is where industrial symbiosis (IS) could play an important role. Where companies traditionally optimize their processes and products within their own value chain, IS can take industry to the next level, as it enables the exploration of options to exchange water, waste, energy and material streams in a greater ecosystem by means of system integration and optimization. This not only has economic benefits, but also potentially a positive environmental impact, and can therefore optimize the greater

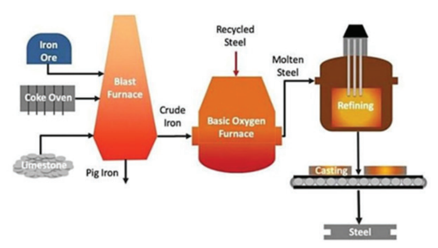

FIG. 2. Schematic representation of a typical blast furnace-based steel mill. Source: ArcelorMittal.

industrial system and contribute to the energy and feedstock transitions.

Of all the steel mill gases, COG has the most significant amounts of impurities—such as ammonia, hydrogen cyanide (HCN), sulfur species [mainly hydrogen sulfide (H_2S)], naphthalene, light oil and tar. The light oil is mainly characterized by benzene (80%–85%) and xylene and toluene (15%–20%). The tar is a highly complex blend that is not easy to process.

Today, a significant proportion of products is derived from olefins obtained from the steam cracking of hydrocarbons. However, the petrochemical industry has a long history of using CO (along with H_2) in syngas chemistry.

In the past, limited access to oil reserves (such as during World War II) was a primary driver for the utilization of syngas chemistry—which ultimately led to the development of Fischer-Tropsch chemistry as an alternative route to chemicals and fuels. In periods of high oil prices, syngas chemistry has been explored for converting alternate carbon sources like coal, biomass, natural gas and waste plastics. Therefore, many companies have a long tradition in the development of syngas conversion technologies.

Since 2015, Dow Chemical, ArcelorMittal and Tata Steel have been exploring the use of H_2-rich COG and CO-rich BFG and/or BOFG as members of an international consortium working on the Carbon2Value project, which explores innovative technology for reducing CO_2 emissions across the major energy-intensive steel sector by 30–45%. The consortium's goal is to use this technology to separate CO_2 streams and to valorize CO and potentially CO_2 in the future. Based on the knowledge that methanol can be produced commercially from COG[1] and ethanol from BOFG and/or BFG,[3] these consortium partners have anticipated that other chemical conversions should be possible, as well.[4]

In parallel, other consortia such as the Carbon2Chem project in Germany are also exploring these options.[5] The goal of this project is to avoid CO_2 emissions by utilizing CO in syngas conversion chemistry—hence, capturing the carbon in the material value chain. This is seen as a more interesting option than post-combustion CO_2 utilization, as CO is more reactive and requires less energy to be converted.

Scope of work. To utilize steel mill gases in the production of chemicals and materials, several challenges have been identified.[6,7] First and foremost, the composition of the gas does not meet typical specifications that can be achieved when methane is used to generate syngas via reforming (either partial oxidation, autothermal reforming or steam methane reforming). CO in the BFG is present in diluted form (with CO_2 and N_2) and contains many impurities. The steel mill gases are saturated with water and contain dust (sulfided iron oxide) and a variety of metals and S and N species. Therefore, the Carbon2Value program focused on three major targets:

1. Removing impurities to bring the gas on spec for downstream conversion
2. Improving process and carbon efficiency through the removal of diluents (N_2, CO_2)
3. Providing technical demonstration of the concept at scale in a relevant environment.

Here we report the efforts on the removal of CO_2 and impurities from the BFG and COG (targets 1 and 2). This work was completed in the framework of an Interreg 2 Seas project (2S01-094) with European Union (EU) co-funding.

After a careful analysis, the research team selected amine scrubbing as the technology to achieve the removal of CO_2 and specific impurities in a single process.[8] While it is quite common to use the direct reduction of iron to capture CO_2 in steel production, to the best of the authors' knowledge, amine scrubbing is only employed in one BFG steel mill and in a few pilot lines. Limited information about these pilot plants is available; however, challenges on the stability of the applied amine, along with details around the quality of the output gas for downstream processing, have not been reported in the public domain.

For this study, a commercial amine product[a] was selected. This is a formulated amine for CO_2 and H_2S removal[9] that is expected to deliver better performance than the cheaper alternative monoethanolamine (MEA). A key area of focus was stability, thus making this an important subject of study. Therefore, the joint research program had the following targets:

1. Assess the feasibility of amine washing with the proprietary solvent[a] to remove CO_2 and sulfur impurities from BFG, and from BFG co-fed with COG and COG
2. Provide a CO-rich product that could be used in a downstream CO conversion unit
3. Deliver data for full-scale plant design for CO_2 capture at steel mills.

Description of the process. To deliver on the research targets, a CO_2 capture pilot line was developed. The unit was engineered by Dow and Petrogas and constructed by Petrogas. The pilot unit was completely enclosed within a 40-ft con-

FIG. 3. Photo of the Carbon2Value CO/CO_2 separation pilot plant installed at the ArcelorMittal steel mill in Ghent, Belgium. The orange pipe contains the BFG that was fed to the unit.

tainer skid (FIG. 3). The container was designed to be easily transported via truck or ship for testing at different locations.

The steel mill gases were supplied to the pilot unit from tie-ins made on the steel plant's internal gas header system. The BFG and COG from the pipelines entered the unit at a slight overpressure (TABLE 2). All treated gases and offgases were routed back into the piping network of the steel mill.

The gas from the steel mill first passed through a set of coalescing filters—two installed in parallel for each feed gas—for high-efficiency removal of sub-micron liquid droplets and solids. Mass flowmeters installed downstream of the filters were used to meter in the gases to the compressor suction.

A process sketch of the acid-gas scrubbing process used in the pilot plant is shown in FIG. 4. The mixed gases were compressed in a single-acting, three-stage positive displacement compressor with interstage cooling and liquid condensate removal. The compressor can deliver gas at a maximum discharge pressure of 32 barg. The compressed gases from the compressor were cooled in a plate-and-frame heat exchanger to 40°C (104°F) with chilled ethylene glycol (EG). A flowmeter measured the flow of cooled gas before it entered the absorber.

In the absorber, the steel mill gases were contacted with the proprietary solvent[a] to remove the acid gases by chemisorption. The absorber—2.8 m in height and 5 cm in diameter—had a single packed bed loaded with stainless-steel pall rings for enhanced gas-liquid contacting. The column was fitted with a demister pad above the packed bed for de-entrainment. Pressure drop over the packed bed was monitored using a pressure differential cell to identify potential foaming or fouling in the packed bed. The column was also fitted with a resonating fork for foam detection at the top of the column. This was specified by Dow Industrial Solutions based on successful commercial scale applications. The bottom level in the column was measured using a guided wave radar and controlled via an air-actuated level control valve. The treated gas from the top of the absorber was measured using a flowmeter. The inlet flow measurements, along with the inlet and outlet stream compositional analysis, enabled the determination of the acid gas removal efficiency in the absorber.

The treated gas left the absorption column overhead and was routed to downstream consumers at pressure. The solvent left the absorption column through the bottom nozzle. The solvent is fully saturated (i.e., rich in CO_2) and is further called "rich solvent."

The rich solvent left the bottom of the absorber and passed through a particulate filter before being flashed in the horizontal flash vessel. The flash gas was removed from the top of the de-entrainment section of the flash, and the pressure was regulated between 4.5 barg–5.5 barg. The rich solvent from the flash vessel was first routed through an activated carbon filter before entering the top of the stripping column. The activated carbon filter removed foam-causing impurities (e.g., dissolved hydrocarbons, degradation products and a variety of surface-active agents) that had entered or formed in the system. Heat tracing was installed on the transfer line from the flash vessel to preheat the solvent to above 90°C (194°F) before entering the stripper column. Typically, on a commercial unit, preheating the solvent is done by a heat exchanger that recovers heat from the lean solvent after regeneration.

The rich solvent entered the top of the regenerator column and contacted stripped gases and water-amine vapors generated in the reboiler over a single packed bed loaded with stainless-steel pall rings for enhanced gas-liquid contacting. The power input to the electrical reboiler was controlled by maintaining a desired temperature at 120°C (248°F) of the solvent. An overflow weir was installed in the vessel to maintain a constant liquid level to submerge the reboiler and ensure adequate liquid residence time in the reboiler. The overflow from the reboiler was routed into a surge vessel that was located directly below the vessel containing the reboiler.

The overhead vapors from the regenerator column were cooled in a plate-and-frame exchanger to 20°C (68°F) with chilled EG. The condensed liquid was recovered from the acid gases in a knockout vessel that had a demister for high-efficiency de-entrainment. The liquid recovered in the knockout vessel was returned to the top of the regenerator column, using a positive displacement pump.

The lean solvent exited the bottom of the surge vessel and was cooled in a

TABLE 2. Typical operational parameters for the CO/CO_2 separation pilot line

Parameter	Value
Input pressure, bara	1.05–1.3
Compressor discharge pressure (normal), bara	29
Compressor mass flow, kg/hr	10
Liquid circulation rate, kg/hr	45
Proprietary solvent[a] in water, wt%	> 45
Absorber temperature liquid inlet, °C	40
Reboiler temperature, °C	120–125 (132 max)

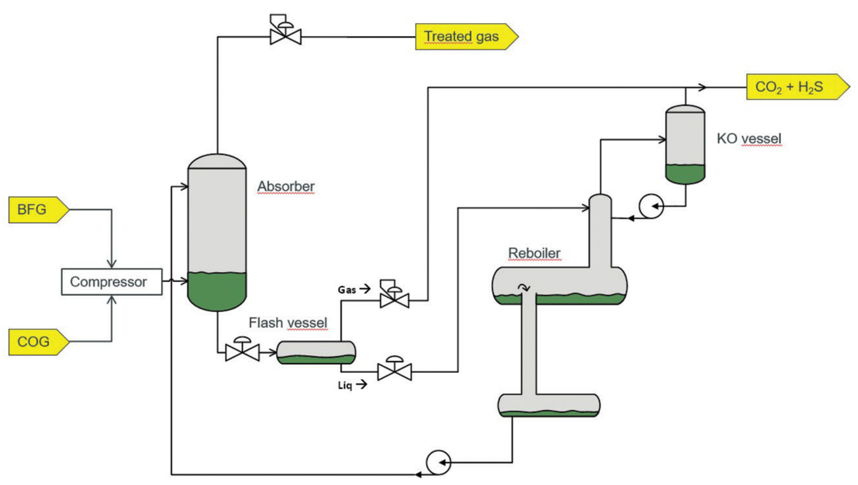

FIG. 4. Schematic representation of the CO_2 removal process applied in this project.

plate heat exchanger to 40°C (104°F) with chilled EG. The cooled solvent was pumped to the absorber. The chilling loop system of a chilled water loop, filled with EG (30 wt%), was cooled to 10°C (50°F) with a chiller unit. The total circulation rate of chilled water was 4 m^3/hr, with a total process flow requirement of 0.4 m^3/hr.

The unit was fitted with an online gas chromatograph (GC) for gas analysis. Of this setup, three gas streams were analyzed online: the outlet of the compressor, the outlet of the absorber and the outlet of the stripper. The analysis of the liquid amine solvent was done offline in the Dow Industrial Solutions lab in Terneuzen, Netherlands. The process GC system was equipped with five parallel chromatographic trains to separate all major components with a cycle time of 300 sec.

To deliver on the research objectives, the pilot line was operated continuously for specific periods of time in 2018–2021.

Results and discussion. The operational period for the pilot line started with commissioning in 2H 2018. Operations commenced in 2019 and continued in 2020–2021. Over time, the unit availability increased, enabling extended campaigns lasting multiple months at a time. The run length was initially limited by excessive pressure drop over the inlet filters. Improvements to the filter design enabled extended run lengths between filter changes.

The data presented here are mostly from 2020 and comprise two periods:

- Experiment 1 (Exp. 1), in which the unit was operated for ~800 hr on BFG only (blue data points), BFG + COG mix (purple datapoints) and COG only (red datapoints)
- Experiment 2 (Exp. 2), in which the unit operated for ~2,500 hr on BFG only.

In total, the unit captured ~2.2 t of CO_2 during Exp. 1 and 9.2 t of CO_2 during Exp. 2, based on mass balancing with the mass flowmeters and gas composition data from the online GC. In Exp. 1, the cleaned gases from the absorber were routed to a downstream unit of LanzaTech, which utilized the treated gas as a feedstock for ethanol production (not reported here).

The CO_2 removal efficiencies during Exp. 1 and Exp. 2 are presented in **FIG. 5.** The data shows that the targeted CO_2 removal efficiency of 90%–95% could be achieved for extended periods of time. During Exp. 1, process conditions were optimized—namely solvent circulation rates and energy input—to reach CO_2 removal efficiencies of 95%–100%, albeit at an increased heating duty in the reboiler.

It was found that performing a detailed energy balance of the system to evaluate energy input per unit mass of CO_2 removed was not possible on the pilot unit. Primarily due to the high relative heat losses at this smaller scale at various locations in the process, it was found that the measured number had a high standard deviation from the actual number. Dow Industrial Solutions supports hundreds of commercial CO_2 capture units, and it has a proprietary empirical model that predicts the performance of such units. For this small-scale pilot, the heating duty was calculated to be 4.2 GJ/mT of CO_2 captured in an idealized configuration. However, the model predicts that this would translate to 2.3 GJ/mT of CO_2 captured in a commercial-scale installation. This is well in line with world-class performance for an amine-based CO_2 capture unit.[12]

The impurities present in COG can lead to foaming, fouling and a higher build-up of heat-stable amine salts (HSAS), which can have a significant negative impact on the performance of the system. HSAS are the amine salts of acidic contaminants that do not thermally split and liberate in the regenerator. In the chemical

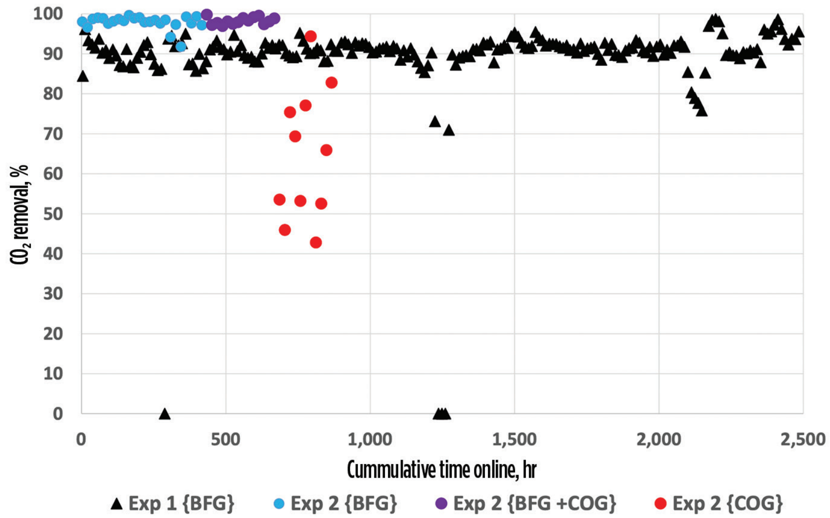

FIG. 5. CO_2 removal efficiencies during Exp. 1 and Exp. 2. In these periods, a total of 2.4 t and 9 t of CO_2 were captured, respectively. Exp. 1 was BFG only (blue data points), BFG + COG (purple data points) and COG only (red data points). Exp. 2 (black data points) was BFG only.

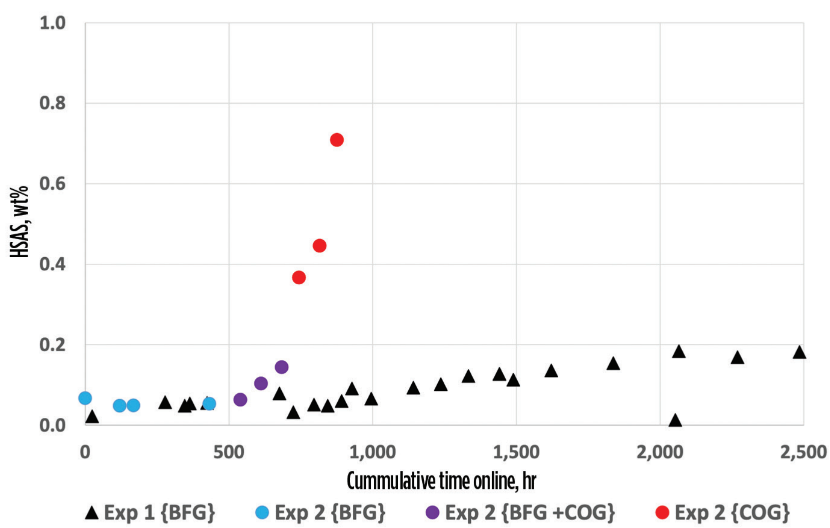

FIG. 6. Concentration of HSAS as a measure of solvent quality for Exp. 1 (black data points) and Exp. 2 (blue, purple and red data points) as a function of time.

analysis of gas treating amines, they are reported as the weight percent of solution that is amine bound as non-regenerable salt. Naphthalene and tar can condense in the solvent to create fouling material and promote foaming, especially at cold spots. They can also act as a binder if other inorganic particles are present in the system and, thus, aggravate these problems. The acidic species can lead to higher levels of HSAS. Although Dow was aware of these potential problems, for the purpose of this project, a robust pretreatment section (or any other measure in the unit) was not considered to minimize the level of these impurities and their impact, except for the use of a proprietary antifoam[b].

FIG. 5 shows that the unit had stable operation during Exp. 1 with BFG only (black and blue data points) and during the run in which BFG was mixed with COG. However, when only COG was processed, unit performance showed a rapid decrease over a period of 1 wk. The red data points show a lower CO_2 capture efficiency and a period of unstable operation because of foaming issues in the system. However, the primary cause for this unstable operation was continuous foaming and fouling of the unit due to the presence of naphthalene, tars and oils in the COG that condensed in the absorber. The continued accumulation of these impurities resulted in unit fouling, which was reflected by a high pressure drop across the absorber column and downstream equipment, such as heat exchangers and coolers.

A unit shutdown took place after Exp. 1, and the unit was opened for maintenance. Process forensics indicated significant fouling in several sections of the unit. The nature of the fouling was identified with several analyses, such as elemental analyses of deposits, microscopy of solid residues and GC-mass spectrometry of organic liquids. Based on these results, it was confirmed that aromatic tars from the COG were present in the installation. These are known to cause foaming and fouling in various gas-liquid separation processes when they condense in the colder parts of the unit (e.g., post-compression coolers). Evidence of foaming was also found on the packing that was loaded into the absorber and stripper column.

Additional design features could improve the feedstock purification, such as an upstream pretreatment (washwater column) or other measures in the unit (skimming systems), especially on the high-pressure side of the unit. Furthermore, the preventative use of the proprietary antifoam[b] would have helped to mitigate the negative impact of the feed gas impurities. However, such improvements were out of scope for this work; therefore, it was decided to discontinue operations with COG. In case COG were utilized as a source of H_2 in steel gas valorization, it was anticipated that, with adequate design considerations, the naphthalene, light oil and tar content of such gases could be addressed.

Tar and light oil are not the only contaminants that can impact utilization potential. Steel gases like BFG, BOFG and COG also contain a significant number of contaminants, such as ammonia (NH_3), HCN, H_2S, carbonyl sulfide (COS) and carbon disulfide, as well as metals such as iron, mercury and arsenic[10,11] and traces of O_2. These can affect the operations directly or indirectly, and a major objective of this study was to assess that impact as a function of time. During operations, liquid samples were extracted from the amine circulation at a frequent rate. Typically, a 250-ml liquid solvent sample was collected every 72 hr from the unit. These samples were analyzed at Dow's laboratories.

Analysis results were used to control the amine concentration in the solvent within a target band of 40 wt%–50 wt%. Water—and occasionally amine—was added to the system to replace the water lost from the system.

More interestingly, the chemical composition of the liquid circulation provided an indication of the impact of the treated gas on the composition of the solvent. An extensive list of organic and inorganic species was monitored, along with important parameters such as pH, color, density and acid gas loading. It should be noted that contaminants in the gas can also cause indirect damage, as they can be converted into other more harmful species upon the chemical reactions caused by the basic nature of the solvent, the temperature in the installation and the presence of metals that might catalyze these side reactions.

It was clear from the regular solvent analysis that, despite the relatively poor quality of the BFG (blue and black data points in **FIG. 6**), the buildup of HSAS was found to be steady, but slow. A somewhat higher rate of formation, although still not critical, was observed when COG was co-fed with the BFG (purple data points) or fed on its own (red data points). The faster growth of the HSAS concentration in these experiments was directly related to the higher concentration of contaminants in the COG. Based on the pilot plant data and operational experience, it was found that untreated COG cannot be fed directly to an amine absorption unit without having a significant impact on the process economics from a capital expenditure perspective (implementation of purification equipment) and an operational expenditure perspective (solvent and energy use). It should be noted that Exp. 2 was terminated because of fouling issues. The upper limit for HSAS was not reached during this experiment.

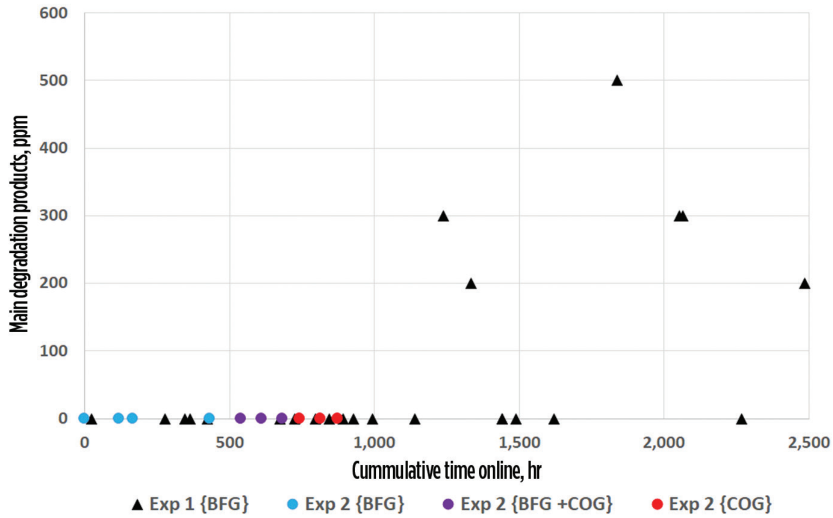

FIG. 7. Buildup of degradation products (i.e., the sum of bicine + THEED + hydroxyethyl ethylene urea + HEED) during Exp. 1 (black data points) and Exp. 2 (blue, purple and red data points) as a function of time. **Note:** Detection limit is ~100 ppmw.

Amine degradation products can be of particular concern when using commodities like primary and secondary amines, such as MEA and diethanolamine (DEA). Examples of associated, problematic degradants include bicine and tris-hydroxyethyl ethylenediamine (THEED), which can result in corrosion of process equipment when not properly managed. Formulated, proprietary amines[c] substantially mitigate these risks.

These species could ultimately build up to a concentration that is undesired and should, therefore, be removed from the process.[12] However, in this study, the formation and accumulation of both HSAS and amine degradation products were not found to be a cause for operational problems, so the replacement of the amine solvent inventory was not necessary (**FIG. 7**). This data clearly illustrated the very low reactivity of the proprietary solvent[a] toward the formation of degradation products vs. generic gas treating solvents.

The primary HSAS encountered in this study was formate (> 80% of the HSAS). The rest of the anions were primarily thiocyanate and acetate. Formate is formed in this system in several different reactions, such as HCN hydrolysis.

For downstream utilization of the CO_2 lean gas, the quality of such gas is critical. Therefore, the CO_2 content in the treated gas was monitored, along with the H_2S, COS and NH_3 contents. These components are typically present at concentrations of 1 ppmw–30 ppmw in the feed gas. Amine solvents are also selective toward sulfur species, and it was observed that a high sulfur removal efficiency could be achieved. The CO_2 lean gas had a measured H_2S concentration between 1 ppm and 2 ppm, and this has the potential to be removed until even lower values under more optimized conditions for H_2S capture. Although this is not zero, and it is still an issue for the use of the CO-rich gas to conduct syngas chemistry, the bulk removal of H_2S and COS would allow for an affordable deep removal of such species in a guard-bed setup prior to entering the downstream CO conversion unit.[6]

The downside of the H_2S capture by the amine solvent was that it is released with the CO_2. Consequently, the H_2S is concentrated in the CO_2 outlet stream with roughly a factor 4 vs. the input concentration. In essence, this means that the CO_2 from treated BFG contains 50 ppm–60 ppm of H_2S, and, when treating COG, this could be as much as 250 ppmw of H_2S. Further purification of the captured CO_2 would need to be considered in case this CO_2 is to be processed further via either carbon capture and storage or carbon capture and utilization. In this respect, it is also important to note that traces of amine could be present in the captured CO_2. The CO_2 from the reboiler was analyzed and was found to contain 1 ppm–2 ppm of the amine, but no NH_3 was detected in the CO_2.

Summary and outlook. A CO/CO_2 separation pilot line was developed and operated with co-funding from the Interreg 2 Seas program. The unit was installed in the heart of the ArcelorMittal steel mill in Ghent, Belgium. This enabled the unit to be fed with real industrial waste gases (e.g., BFG and COG) directly from the major gas lines in the facility.

In the 2019–2021 timeframe, the unit was mainly operated on BFG. It was shown that the inlet filters were effective in removing (acid) condensate and dust from the feed gas. Operation on COG demonstrated that the current filter design did effectively remove the tars present in this gas. Consequently, severe process upsets were observed in the run with COG, mostly due to foaming and fouling caused by the presence of aromatic tars in the amine solvent. Additional measures to clean COG are needed to utilize this gas.

Several thousand hours of operation with BFG demonstrated that the applied proprietary solvent[a] can capture CO_2 from BFG at greater than 90% efficiency with minimal degradation. More than 95% efficiency was achieved under optimized conditions. In addition, H_2S and COS in the gas were also captured, resulting in a treated gas with H_2S and COS in a low ppm range (i.e., 1 ppm–5 ppm). This enabled the use of the CO_2 lean gas for CO conversion chemistry, which is typically less tolerable for impurities and requires sub-ppm levels. Although deep removal for chemical conversion is still required, the bulk of the sulfur impurities can be effectively removed using an amine system. A trial with LanzaTech fermentation technology for ethanol production from BFG was conducted successfully. In a follow-up project, for which the CO/CO_2 separation pilot line will serve as a feedstock pretreatment, the project partners will explore the subsequent polishing and catalytic conversion of the CO-rich gas.

It was also demonstrated that the relatively poor quality (dust, impurities) of the BFG had limited effect on the long-term quality of the proprietary solvent[a]. Consequently, it was anticipated that an excessive make-up of the amine solvent would not be required, which had a positive impact on the operational costs. As expected, while still not critical for the process, the much poorer quality of the COG showed a higher degradation rate for the solvent. In combination with the observed fouling of the unit when running on this gas, it was decided that amine wash was not a good solution for treatment of COG and/or BFG + COG mixtures without any upstream pretreatment for tar and oil removal to values of less than 100 ppm.

Operations with BFG also confirmed that amine carryover to the CO_2 was low and that the energy for solvent regeneration was in line with expectations and on par with typical numbers for this technology (i.e., 2.3 GJ/mT–4.2 GJ/mT CO_2 captured). This energy use could be significantly improved when heat integration with the exothermic CO conversion process was implemented.[13]

The quality of the captured CO_2 remains a challenge. As the amine solvent also captured the sulfur species, these will concentrate in the CO_2. Consequently, H_2S levels of 50 ppm–250 ppm were observed. To be able to send this CO_2 for storage and/or utilization, desulfurization of the CO_2 must be considered. A suitable technology for this could be Villadsen's electrochemical desulfurization.[14] HP

ACKNOWLEDGMENTS

This project was performed by the Carbon2Value consortium and co-funded by the EU's Interreg 2 Seas program (Project 2S01-94). The authors kindly acknowledge numerous internal and external contributors to the project, and our external partners at ArcelorMittal Ghent, Petrogas BV, Dow Industrial Solutions, Dow Chemical Lab, Dow Hydrocarbons R&D, LanzaTech, Provinciale Ontwikkelingsmaatschappij Oost-Vlaanderen (POMOV), the University of Lille in France, the Institute for Sustainable Process Technology (ISPT), and Impuls Zeeland (Smart Delta Resources program).

NOTES

[a] Dow Industrial Solutions' UCARSOL™ AP 814 solvent

[b] Dow Industrial Solutions' UCARSOL™ GT-10 antifoam

[c] Dow Industrial Solutions' UCARSOL™ amines

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Complete literature cited available online at www.HydrocarbonProcessing.com.

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An economic evaluation for SO_x emissions reduction from FCC regenerator flue gas using an additive

Sulfur oxides (SO_x) removal has been a global trend in the refining and petrochemical industry. SO_x reduction additives and wet gas scrubbers (WGSs) are the two most widely used methods to reduce SO_x emissions from fluid catalytic cracking (FCC) flue gas in addition to feedstock hydrorefining. SO_x reduction additives can remove SO_x from the FCC regenerator flue gas with low cost, high efficiency and flexibility. In theory, flue gas SO_x could be reduced to an extremely low level if the proportion of additives was not limited.

However, in a practical FCCU, refiners must consider how to achieve SO_x reduction in the most economical way. Based on the application of a proprietary SO_x-reduction additive[a] in 25 different FCCUs with WGSs, the economic benefits of the application of the SO_x-reduction additive were evaluated and the most cost-effective ways to use the additive under different regeneration conditions were predicted.

The cost of SO_x additives vs. the cost of caustic in WGSs.

The main reaction in WGSs is $SO_2 + 2NaOH = Na2SO_3 + H_2O$, so a linear relationship exists between the apparent consumption of caustic and sulfur dioxide (SO_2) removal in a certain range of SO_2 concentration. The efficiency of additives to capture SO_2 is determined by what is called the pick-up factor [(PUF): the mass of SO_2 captured by additive per unit mass]. Assuming that the unit price of caustic with 30 wt% NaOH is P_1 and that of the SO_x-reduction additive[a] is P_2, then the break-even point of additive can be calculated as follows (Eq. 1):

$$1/PUF \times P_2 \leq 1/64 \times 40 \times 2/30\% \times P_1 \qquad (1)$$
$$PUF \geq 0.24 \times P_2/P_1$$

Therefore, it would be more economical to use SO_x additives than to consume caustic in WGSs when the PUF of the additive was greater than $0.24 \times P_2/P_1$ kg SO_2/kg additive. It should be noted that the actual cost savings would be even higher since the simplified model did not consider sulfur trioxide (SO_3) capture—it is generally believed that the additive is more effective than WGSs in SO_3 capture—the benefits of sulfur recovery, the cost of treating high-salt wastewater and the WGS plant investment.

Prediction of PUF and maximum cost savings.

The PUF is closely related to the properties of SO_x additives and the operating conditions of FCCUs. The additive properties lie in effective magnesium oxide (MgO) utilization, the ability to promote the conversion of sulfur (S) compounds to SO_3 in the regenerator, and the ability to reduce sulfate to hydrogen sulfide (H_2S) in the reactor. A good SO_x-reduction additive should also balance the high reactant accessibility and low attrition index.

The operating conditions are embodied in the following aspects. Flue gas excess oxygen content is the decisive factor to some extent because it determines the conversion of S compounds to SO_3 in the regenerator. The initial SO_x concentration determines the mass transfer force so that higher SO_x concentration results in a higher PUF. Increasing the catalyst circulation rate increases the availability of fresh metal oxides for SO_x

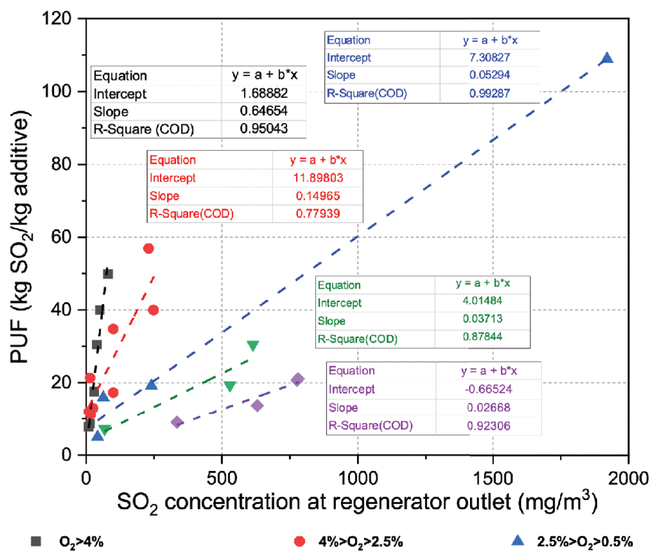

FIG. 1. The relationship between the PUF of the proprietary and the regenerator outlet SO_2 concentration under different excess oxygen conditions.

pick-up and, therefore, reduces SO_x emissions. Lower regenerator temperatures tend to favor SO_3 formation, while good air distribution and mixing in the regenerator enhance SO_x pick-up. The FCC catalyst itself and the presence of a carbon monoxide (CO) promoter also affect the SO_x capture efficiency of the SO_x-reduction additive, to a certain extent.

To enhance the efficiency of flue gas SO_x pick-up, the authors' company developed the enhanced RFS additive[a], which specifically improved the content of the key active component MgO. At the same time, the content of oxygen storage components were adjusted to improve the SO_x removal efficiency under the condition of low excess oxygen, including partial burn regeneration. In addition, the preparation process of the additive[a] was optimized to maintain good attrition resistance and avoid adverse effects on SO_x removal efficiency and unit operation. The authors' company completed industrial trial production in 2014 and the additive has been successfully applied in more than 40 FCCUs.

The concentration of SO_2 and excess oxygen in the regenerator are the two key factors affecting the PUF for the same grade of additives. Here, the PUF of the additive was fitted as functions of SO_2 concentration at the regenerator outlet under different excess oxygen conditions based on the application of the proprietary additive[a] in 25 different FCCUs. It was found that these units could be divided into five categories according to excess oxygen content and regenerator form. The fitting of each category presents a good linear correlation, as shown in **FIG. 1.**

Based on this, the PUF of the additive under different operating conditions can be predicted. It was found that the PUF value increased with the increment of excess oxygen of the regenerator and outlet SO_2 concentration. To identify the cases where using additives is more economical than using caustic in WGSs, the difference between the two costs was expressed as the following equation (Eq. 2):

$$\varphi = 80/64/30\% \times \alpha \times \omega(SO_2) \times Q \times P_1 - \alpha \times \omega(SO_2) \times Q \times P_2/PUF \quad (2)$$

where:

φ = cost savings using additive over caustic, \$/hr
α = SO_2 removal ratio using additive
$\omega(SO_2)$ = mass concentration of uncontrolled SO_2 in the original flue gas, mg/m^3
Q = flue gas flowrate under normal conditions, 10^6 Nm^3/hr
P_1 = unit price of caustic with 30 wt% NaOH, \$/kg
P_2 = unit price of SO_x reduction additive, \$/kg

Combined with the calculated PUF values under different operating conditions in **FIG. 1,** the maximum value of φ can be obtained.

Three FCCUs are listed as examples in **FIG. 2:** two units in the CNOOC Refinery Co. Ltd. Huizhou refinery (HZ-1 and HZ-2) and one in the SINOPEC QD Refining & Chemical Co. Ltd. (QD). The excess oxygen of HZ-1 is greater than 4%, and the excess oxygen of QD is between 2.5% and 4%, while HZ-2 adopts partial burn regeneration with excess oxygen of less than 0.1%. Details of the three FCCUs are described below.

Using the fitting relationship in **FIG. 1** can predict the optimal economic benefit of the three units, as shown in **FIG. 2.** It is predicted that the maximum economic benefit would be about \$13/hr and \$80/hr after the application of the additive[a] in the HZ-1 and HZ-2 units while the removal ratio is about 80% and 47%, respectively.

Similarly, the QD unit is expected to save about \$79/hr with a removal ratio of about 75% after the application of the additive. It should be noted that when the additive is initially added, the PUF is very high due to the high initial concentration of SO_2 in the regenerator; however, the insufficient amount of additive cannot remove enough SO_2 so the removal ratio is not high. In this case, it is more cost-effective to capture this part of SO_2 with the SO_x-reduction additive than with caustic in WGSs.

Once the additive amount exceeds a certain value when the excess oxygen is not high enough, the removal of SO_2 requires much more additive supplement than before—in this case, the cost of using additive has skyrocketed and is not cost-effective. This is reflected in the rapid decline of the curve in **FIG. 2.** The capture efficiency of additive is very low under marginal conditions. In incomplete regeneration, some S compound exists in

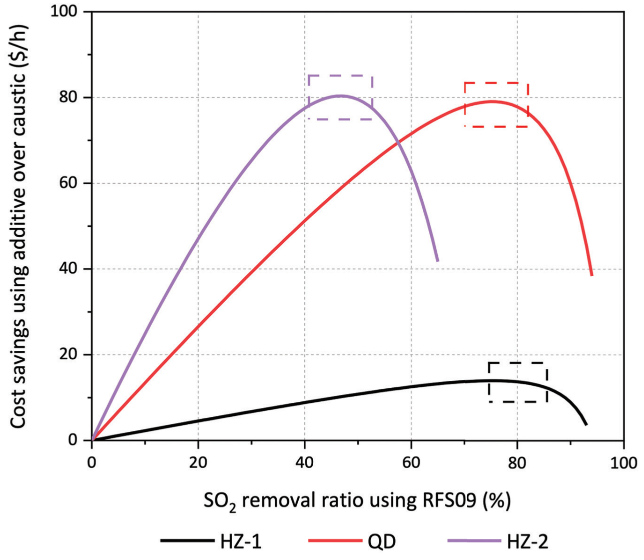

FIG. 2. The expected economic benefits of the three refineries.

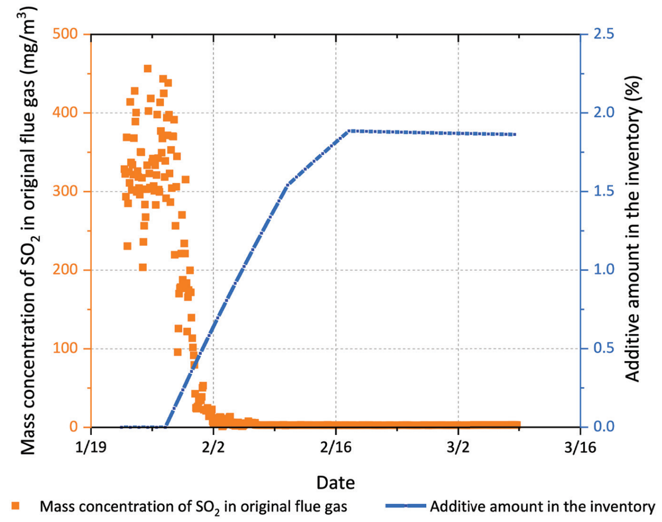

FIG. 3. The SO_2 concentration in the flue gas during the additive application in the HZ-1 unit.

the form of H_2S and COS, which are difficult to transform and capture by additive. These S compounds are transformed into SO_x in a CO boiler, so the refinery must use post-treatment like a WGS to meet the requirements of local environmental laws and regulations.

DETAILED ANALISYS OF APPLICATION CASES

Case 1: HZ-1 unit in the CNOOC Refinery Co. Ltd. Huizhou refinery. The HZ-1 is an MIP unit with a designed annual processing capacity of 1.2 MMtpy. The mass fraction of sulfur in the feedstock ranged from 0.35 wt%–0.41 wt%. The regenerator adopted full burn operation with a pre-combustor. The total air volume to the regenerator was 0.13×10^6 Nm^3/hr and the excess oxygen in the flue gas was 4.8%–5.5%. The mass concentration of SO_2 in the flue gas at the entrance of the WGS was 300 mg/m^3–400 mg/m^3 before the additive[a] was used. After using the additive, SO_2 was reduced to less than 20 mg/m^3 when the additive inventory was less than 2%, and the removal ratio was about 95% (**FIG. 3**).

The caustic consumption decreased from 150 kg/hr to about 10 kg/hr, which is consistent with the removal ratio of SO_2, and sometimes even stopped filling caustic. Total dissolved solids (TDS) in wastewater decreased from more than 10,000 mg/kg to 1,300 mg/kg with the addition of the additive[a] (**FIG. 4**). The SO_x in the flue gas was greatly reduced after being captured by additive, and the amount of caustic was reduced, thus reducing the salt content of Na_2SO_3 and Na_2SO_4 in water. TDS reduction not only benefits wastewater treatment and slows down equipment corrosion, but it also reduces the risk of system scaling, which is conducive to long-term stable operation of the unit.

Considering that the additive has a good effect on TDS and solves the problem of plume trailing subsidence from the WGS caused by SO_3 aerosol, it was used to reduce the SO_x of the flue gas before the entrance of the WGS to a very low level, rather than only reducing by 80% for the consideration of optimal economic benefit. Assuming that the price of caustic with 30 wt% NaOH was \$173/MMt and the cost of consumption of the additive was considered, the total savings was about \$4/hr in this case, which is still economical. This value is also consistent with the predicted value in **FIG. 2.**

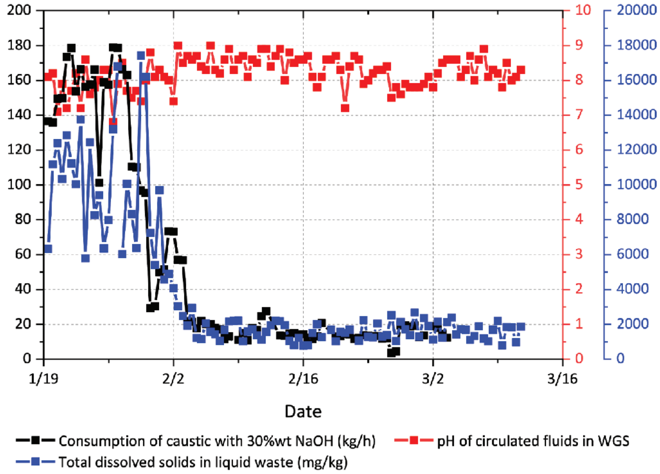

FIG. 4. Consumption of caustic and TDS in liquid waste during the additive application in the HZ-1 unit.

Case 2: HZ-2 unit in the CNOOC Refinery Co. Ltd. Huizhou refinery. The designed annual processing capacity of the HZ-2 FCCU in the Huizhou refinery was 4.8 MMtpy with an S content in the feedstock between 0.35 wt% and 0.39 wt%. The unit adopts a two-stage, coaxial up and down incomplete regeneration process with excess oxygen of less than 0.1%. The total air volume to the regenerator was 0.32*10^6 Nm^3/hr and the CO volume concentration at the outlet of the regenerator was 3.2%–4.5%. When no additives were used, the mass concentration of SO_2 in the flue gas at the entrance of the WGS was approximately 1,400 mg/m^3–1,800 mg/m^3. The SO_2 removal ratio was 55% when using 3.8% additive[a] in the inventory, and the consumption of caustic decreased from 2,200 kg/hr to 1,100 kg/hr (**FIG. 5**), saving about \$72/hr. This value is close to the predicted optimal economic operation in which the maximum economic benefit was \$80/hr with a 47% SO_2 removal ratio.

Case 3: QD unit in the Sinopec QD Refining & Chemical Co. Ltd. The QD unit is an MIP-CGP unit with a designed processing capacity of 2.9 MMtpy. The feedstock oil is mainly hydrogenated VGO with an S content of 0.35%–0.40%. The regenerator adopted full burn operation with a pre-combustor. The total air volume to the regenerator was 0.336×10^6 Nm^3/hr and the excess oxygen in the flue gas was 2.1%–3.2%. The mass

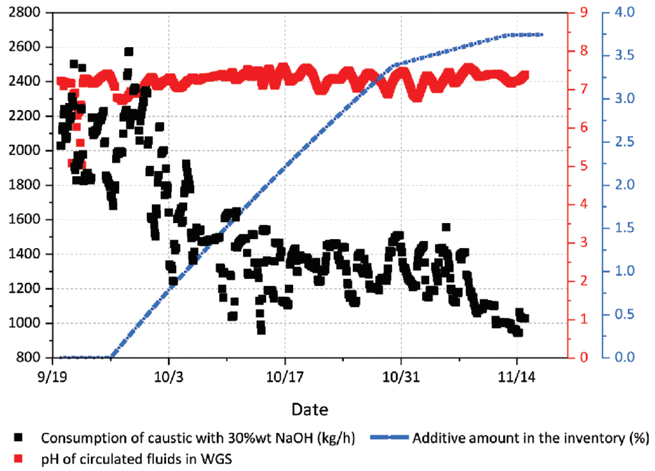

FIG. 5. Consumption of caustic during the additive application in the HZ-2 unit.

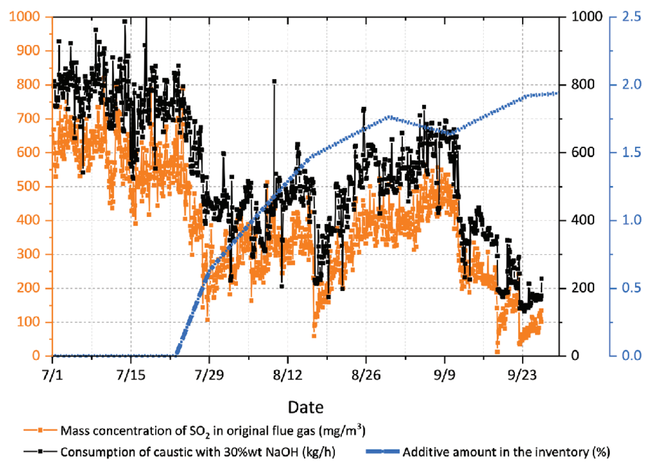

FIG. 6. The SO_2 concentration in the flue gas and consumption of caustic during the additive application in the QD unit.

concentration of SO_2 in the original flue gas at the entrance of the WGS was about 600 mg/m^3 without additives. The SO_2 concentration decreased rapidly to about 250 mg/m^3 with the addition of the additive[a] at the end of July. When the additive was not added due to dredging pipeline and catalyst storage tank replacement in August, the SO_2 concentration came back to about 400 mg/m^3. After the normal addition was resumed in September, the mass concentration of SO_2 decreased rapidly again and stabilized to about 100 mg/m^3. The results showed that the removal ratio of SO_2 reached 80% when the sulfur transfer agent was added at 2% of catalyst inventory.

Under the same pH value of controlled circulating liquid in the WGS, the total consumption of caustic decreased gradually from about 800 kg/hr to about 130 kg/hr–200 kg/hr with the addition of the additive[a], which was consistent with the removal ratio of SO_2 in flue gas, as shown in **FIG. 6.** The economic benefit is about \$71/hr, almost the same as predicted. In addition, the problem of plume tailing from the scrubber was well controlled. The TDS in the circulating liquid decreased from about 4% to about 1%. With the addition of the additive, the mass

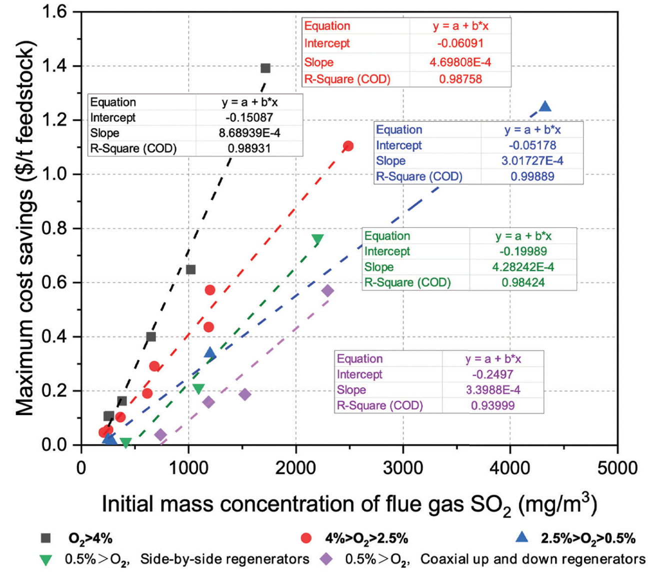

FIG. 7. Maximum cost savings using the additive over caustic.

concentration of chemical oxygen demand (COD) decreased from 100 mg/l–150 mg/l to 20 mg/l–30 mg/l. This is also attributed to the reduction of SO_2 in the original flue gas and the reduction of sulfite and its corresponding COD in water.

An economic model for predicting maximum cost savings using the proprietary additive[a] over caustic under different operating conditions was established in **FIG. 7.**

Assuming that a mass concentration of uncontrolled SO_2 in the regenerator flue gas was 1,000 mg/m^3 and the price of caustic with 30 wt% NaOH was \$173/MMt, the additive would provide a maximum cost savings of \$0.72/MMt of feedstock, with excess oxygen greater than 4%, \$0.41/MMt of feedstock with excess oxygen between 2.5% and 4%, and \$0.25/MMt of feedstock with excess oxygen between 0.5% and 2.5%. If the concentration of uncontrolled SO_2 was higher, greater economic benefits would be obtained.

Takeaway. The PUF of the additive has been fitted as a function of SO_2 concentration at the regenerator outlet and good correlations have been established based on the application of the additive in 25 different FCCUs under 5 different operating conditions. To identify the cases where using the additive is more economical than using caustic in a WGS, a model was built to show the difference between the two costs, and the economic benefit of the additive was evaluated. The most cost-effective way to use the additive in FCCUs with a WGS has been predicted under different regeneration conditions. Three FCCUs are listed as examples to demonstrate the accuracy of the model. The actual total cost savings from the application of the additive are consistent with the prediction of the model. The additive also has the benefit of reducing total dissolved solids (TDS) and chemical oxygen demand (COD) in liquid waste and solves the problem of plume tailing caused by SO_3 aerosol in scrubber stacks. HP

NOTES

[a] SINOPEC's RFS09

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Why sulfur plants fail: An in-depth study of sulfur recovery unit failures—Part 1

Equipment malfunction or an unplanned shutdown of a sulfur recovery unit (SRU) can have a significant effect on a production company's profitability, along with an equally serious impact on personnel safety and the environment. The goal of this article is to establish the highest-probability threats to—and to focus industry attention on—the reliability of sulfur recovery facilities. These threats were identified by analyzing hundreds of cases of SRU failures investigated by the author's company over the last 30 yr to understand the root causes of these failures. Failure pathways include corrosion, plugging, temperature excursions, explosions and process gas/fluid releases. This article also offers the most effective strategies to prevent these failures.

The SRU. The role of the SRU is to convert the hydrogen sulfide (H_2S) present in various industrial process gases—such as acid gas, sour water stripper (SWS) gas and other gases with sulfur species—to elemental sulfur. Government regulatory agencies typically specify the sulfur recovery efficiency (the percentage of inlet H_2S to be recovered as elemental sulfur) required for each facility, or they specify the maximum allowable sulfur species emissions (H_2S, sulfur dioxide, or total sulfur species) allowed from each facility. The SRU technologies that are available to meet these regulatory requirements, and the operating conditions required to achieve optimal efficiencies, are well known, and many other articles have dealt with the various reasons why SRUs may fail to achieve their efficiency/emissions requirements.

This article will not focus on the topic of regulatory failures but will address physical/mechanical failures of SRUs. Physical failures can seriously damage SRU equipment, minimize SRU throughput or shutdown an SRU completely, causing oil/gas/chemical production losses and associated profitability and repair costs. These physical failures can also have serious environmental and safety implications, with the worst cases resulting in injury or death.

The author's company has provided consulting services to sulfur recovery and related industries (such as amine treating, sour water stripping and dehydration) for more than 50 yr, with documented cases going back more than 30 yr. During this period, the author's company has conducted more than 3,000 projects in more than 60 countries, and currently manages between 200 and 300 projects per year, including a constantly increasing number of mechanical failure investigations. While this historical work does not cover the entirety of SRU failure cases, it is likely the largest collection of SRU failure case studies in the world and can therefore provide a valuable window into the frequency of, and the repercussions associated with, various failure mechanisms.

This article will focus on the highest probability threats to SRU facilities and on general strategies to identity and mitigate each of the different failure mechanisms. **Note:** The case numbers cited in the article are based on relatively serious incidents only, usually for cases that resulted in shutdowns, lost production, serious equipment damage and recordable incidents. While more minor cases in all failure categories are still extremely common, these were excluded from the case counts to better focus on the results.

FAILURE TYPES

For the purposes of this article, physical and mechanical failures in SRUs have been divided into five main categories (in order of prevalence): corrosion, plugging, temperature excursions, process fluid (gas/liquid) release and explosions. A description of each category, along with case number estimates, examples, consequences and recommendations for investigation and prevention, are presented in each of the following five sections.

Corrosion. SRU vessels and piping are mostly constructed from carbon steel. SRU condenser tube welds, condenser tubes and vessel corrosion allowances are usually on the order of 0.125 in. (125 mil), meaning that corrosion rates of a few mil/yr can be accommodated and dealt with during scheduled turnarounds. However, higher corrosion rates can result in a loss of containment in days, weeks or months—resulting in unscheduled shutdowns and possible process fluid releases. Corrosion scenarios in SRUs (FIG. 1) typically fall into four categories. These include the following:

- **High-temperature H_2S sulfidation**
  - Corrosion rates become concerning around 300°C (572°F) (9 mil/yr)[1]
  - Corrosion rates increase rapidly as temperatures increase [e.g., 37 mil/yr at 400°C (752°F)][1]
  - Normal process temperatures at or above this range exist in the reaction furnace and wasteheat boiler (WHB), as well as in some catalyst beds

FIG. 1. Examples of SRU corrosion

and some condenser inlets

- **Low-temperature solid sulfur/liquid water contact corrosion**
    - Typical corrosion rates of 50 mil/yr–70 mil/yr[2]
    - Can be as high as 500 mil/yr, depending on conditions and species present[2]
    - Most common in condenser outlets and in liquid sulfur collection and storage, and can occur anywhere the metal temperature falls below 119°C (246°F), which is the freezing point of sulfur
- **Sulfuric acid (SO_3) corrosion**
    - SO_3 is not normally present in SRU gas streams, due to the reducing chemistry of the process
    - Most SO_3 is created in the incinerator under oxidizing conditions
    - Has a dewpoint (condenses as liquid sulfuric acid) that depends on concentration; dewpoint ranges from 90°C–200°C (194°F–392°F)[3]
    - Depending on pH, corrosion rates can be more than 100 mil/yr
- **Water-side corrosion**[4]
    - Various corrosion mechanisms, including oxygen and alkalinity, among others
    - Corrosion rates depend on the mechanism and can be very rapid.

The author's company's case studies include hundreds of corrosion incident investigations and number around 25/yr–30/yr, making corrosion the most common failure mechanism category. High-temperature H_2S corrosion (most commonly on WHB tube sheets and WHB outlets) and low-temperature frozen sulfur contact corrosion (most commonly on condenser outlet pipes and sulfur storage vessels) are by far the most numerous and are relatively equally represented in the case files (10/yr–12/yr). This indicates that, despite the constantly improving understanding of these corrosion mechanisms and how to avoid them, they continue to be extremely prevalent. Most of the recent case studies have found that the SRU design is not usually the problem (i.e., vessels and piping are usually designed to maintain suitable metal surface temperatures), but that the corrosion results primarily from poor construction practices, poor maintenance, and poor understanding by plant personnel of the importance of skin temperature regulation.

SO_3 corrosion case studies are less prevalent, averaging around 2/yr. The most common location for this type of corrosion is in heat exchangers located downstream of the incinerator, where the exchanger tube wall temperatures can easily drop below the SO_3 dewpoint, although corrosion of the incinerator stack and the incinerator emissions analyzers have also been noted at many locations.

Water-side corrosion is the least prevalent in the case files, with only a handful of incidents determined to be definitively linked to water-side corrosion mechanisms alone. This may be because water quality is usually carefully monitored and adjusted at most facilities by outside water treatment specialists, and because the other three process-side corrosion mechanisms are simply more likely. Regardless, water-side corrosion does occur and must still be treated properly in the design and operation of the SRU.

Incident investigations for corrosion failures should always begin with the exact location of the failure (i.e., the hot end or cold end of a condenser or WHB tube) and include detailed photographs and inspections of the failure areas. Water-side corrosion failures can often be easily distinguished from process-side corrosion with a visual determination from which side the corrosion progressed—while high-temperature H_2S corrosion and low-temperature wet sulfur contact corrosion can often be distinguished by the operating temperature and conditions at the exact failure location. SO_3 corrosion can often be easily identified by the presence of a green iron sulfate corrosion product that is not present with other mechanisms, and by the fact that it can only occur downstream of an oxidizing location (e.g., an incinerator). Unfortunately, many incident investigations only begin after the corroded areas or vessels have been removed and replaced without detailed examination, meaning that the most likely root cause must be estimated based on a process review only.

Regarding corrosion prevention, the following recommendations are associated with the most common root causes:

- **High-temperature H_2S sulfidation**
    - Ensure proper design, installation and maintenance of refractory and ferrules in high-temperature SRU areas—areas that will, or might, operate hotter than 300°C (572°F). Refractory and ferrule design should be conducted by competent personnel and should ensure that metal surfaces will be below this temperature limit where possible. Installation and maintenance of these materials should also be conducted and supervised by competent personnel with strong experience in these areas. Following the installation of these materials, it is important to use proper dry-out/curing procedures as recommended by the material supplier.
    - Utilize proper operating procedures that will not damage the refractory and ferrules, especially during high-temperature operating conditions like fuel-gas firing (e.g., startups, shutdowns and hot standbys) and oxygen enrichment conditions. This includes operating procedures that will avoid overheating or melting these materials, and which are usually based on a safe maximum temperature (allowing for measurement errors and temperature variabilities) of around 1,550°C (2,732°F). This also includes procedures that will avoid thermally shocking the materials—usually defined as heating/cooling them faster than the normally recommended maximum of 50°C/hr.
    - Measure reaction furnace refractory wall (as opposed to process gas) temperatures, usually through a specialized full-time thermocouple located at the refractory wall or through a pyrometer designed to measure refractory temperatures. Temporary thermocouple installations can also be used where appropriate, especially during low-temperature startup conditions. Finally, simulations can be used to determine process temperatures based on process conditions and can be used to confirm conditions that might

result in damaging temperatures regardless of the reported values.
  - Ensure proper external heat release from the reaction furnace, so that the shell temperature will not increase significantly beyond the temperature achieved by the internal refractory. The reaction furnace is the only vessel that should not be insulated; instead, a thermal shroud should allow heat to escape from the furnace shell without wind, rain or snow having a direct impact on the shell.
  - Use proper boiler feedwater chemistry and proper blowdown procedures to minimize the buildup of scale on boiler tube surfaces and to ensure maximum heat transfer and minimum tube-wall temperatures.
  - Consider the use of stainless-steel materials in locations where the metal temperatures cannot be maintained below the recommended limit or where the use of refractory materials is impractical (i.e., catalyst bed grating and support mesh).
  - Conduct regular external piping and vessel metal temperature scans to look for temperatures above the recommended maximum. In cases where internal refractory failures have occurred, temporary external cooling measures (i.e., steam or air blowing on the metal surface) can help limit corrosion until the refractory can be repaired.
- **Low-temperature solid sulfur/liquid water contact corrosion**
  - Properly insulate all vessels and pipes downstream of the reaction furnace. Insulation should be designed to keep metal surface temperatures hotter than 119°C (246°F).
  - In addition to insulation, consider the use of external heating [typically, 50 psi (345 kPa) steam heating] in the areas that operate at the lowest temperatures [usually anything below 150°C (302°F)]. This type of external heating is already in common use in many areas of sulfur plants (e.g., liquid sulfur rundown lines, transfer lines and seal/storage devices), but it is also useful protection in other areas, such as in condenser outlets and long-tail gas lines.
  - Replace all insulation and external heating elements as soon as possible if they are ever removed for inspection or repair. Regularly check all steam heating loops—including all steam traps—to ensure that they are properly installed and operating.
  - Conduct regular external piping and vessel metal temperature scans to look for temperatures below the recommended minimum and add insulation or external heating where required.
  - Include a proper sweep of the SRU during shutdown procedures to remove as much sulfur as possible before the unit is shut down and opened to atmosphere. In cases where the plant will be left shut down for long periods, incorporate further mechanical sulfur-cleaning steps in combination with moisture-prevention steps (i.e., nitrogen blanketing).
- **SO_3 corrosion**
  - Where possible, control SO_3 formation in oxidizing locations by minimizing both excess oxygen levels and temperatures. For acid gas-fired reheaters, make routine flowmeter checks and analytical checks to ensure that they are being operated well below stoichiometry (usually 60%–75% of stoichiometry). For incinerators, these should ideally be operated with 2%–3% excess oxygen in the effluent gas, and, in the worst case, with no more than 5% excess oxygen. Incinerators should also be operated at the lowest temperature that achieves the required levels

FIG. 2. Examples of SRU plugging.

of contaminant destruction and plume dispersion. Many facilities operate much hotter than the required temperature due to poor understanding of incinerator operations or because of license requirements.[5]

  - Use SO_3 dewpoint estimates[3] to determine the expected incinerator dewpoints under both normal and worst-case conditions. Where possible, keep metal temperatures (both bulk process gas temperatures and metal wall temperatures) downstream of oxidizing locations above the estimated SO_3 dewpoint for all cases. Ensure that operating conditions minimize the amount of time spent under worst-case conditions, including during startup and shutdown operations, since these can result in temporary SO_3 condensation.
  - When considering heat recovery downstream of an incinerator, either ensure that the design minimizes the risk of crossing the SO_3 dewpoint on metal surfaces (including exchanger tube walls) or reconsider whether heat exchange is an acceptable design option.
- **Water-side corrosion**
  - Ensure that water treatment and monitoring satisfy vendor recommendations.
  - Follow the vendor recommendations regarding continuous and intermittent blowdown rates.
  - Conduct routine water-side inspections and cleaning whenever the sulfur plant is down and available for inspection.

Plugging. Plugging of SRUs can occur anywhere in the liquid sulfur flow path (i.e., through the rundowns and seal devices) or through the process gas flow path (**FIG. 2**). The root causes through either of these pathways typically fall into one or more of the following five categories:[6]

- **Solid sulfur**
  - Has a freezing point of 119°C (246°F)
  - Can occur anywhere in the SRU (with enough heat loss), but most likely in cooler locations, such as in condenser outlets and in liquid sulfur collection and storage areas
- **Elemental carbon (soot)**
  - Most soot is created by improper fuel gas firing during startups and shutdowns
  - Soot can be continuously created in poorly operated fuel gas-fired reheaters and tail gas unit (TGU) burners
  - Can be created in the reaction furnace during large spikes in feedgas hydrocarbon levels
  - Usually gets filtered out across catalyst beds or deposits in low areas such as condensers and rundowns
- **Iron corrosion products**
  - Created by the mechanisms discussed in the Corrosion section of this article
  - Can cause plugging where created (i.e., in condenser tubes) or can collect in low points like condensers and rundowns
- **Alumina fines**
  - Comes from refractory or catalyst dust
  - Dust is usually created during catalyst or refractory installation, and is not typically created during normal operation
  - Deposit occurs immediately downstream of where it is created, most commonly in condensers and rundowns
- **Ammonia salts**
  - In SWS gases, ammonia can react with carbon dioxide to produce salt at temperatures below 85°C (185°F)
  - Salts are most common in SWS lines and knockout drums
  - Ammonia can react with SO_3 to produce salt at temperatures below 280°C (851°F)
  - Some ammonia is always present in SRUs processing SWS gas, but SO_3 can only be created in oxidizing areas like acid-gas-fired reheaters
  - Ammonia salts are most common in condensers downstream of improperly operating fired reheaters.

The author's company has many hundreds of plugging case studies, accounting for around 25/yr–30/yr, tying plugging with corrosion as the most common failure mechanism category. Plugging issues due to solid sulfur, soot and corrosion products are all relatively equally common, at around seven cases/yr. Plugging cases due to catalyst or refractory fines are less common, at around two cases/yr—and these cases almost always occur right after startup in plants that did not conduct proper cleaning of vessels. Plugging due to ammonia salts is the least common incident, with less than one case/yr, but this type of plugging tends to be very rapid when it does occur. These case counts are only for significant plugging issues that resulted in large throughput decreases or complete shutdowns—and minor plugging cases (e.g., a temporary blockage of a liquid sulfur rundown) are extremely common.

Incident investigations for plugging issues can be significantly aided if samples

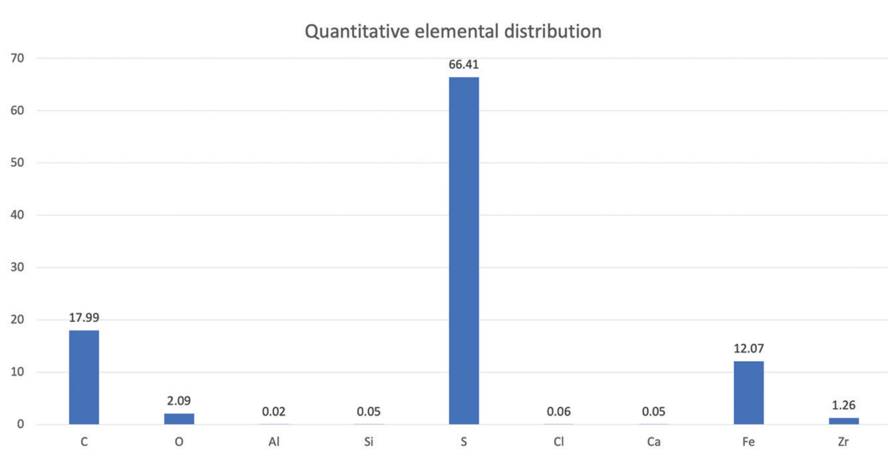

FIG. 3. EDS analysis example.

of the plugging material are available. In these cases, samples can be analyzed for elemental breakdown by x-ray dispersive spectrometry (EDS), which can immediately identify the plugging components (**FIG. 3**). Otherwise, if samples are not available, the incident investigation usually involves the determination of the plugging location (from a detailed pressure survey of the plant and visual examination of all liquid sulfur rundown lines) in combination with a review of the operating conditions and history to determine the most likely root cause.

Regarding the prevention of plugging, the following recommendations are associated with the most common root causes (Note: A more detailed discussion of plugging mechanisms and recommendations on avoiding and reversing plugging can be found in literature[6]):

- **Solid sulfur**
  - Prevent sulfur freezing through proper design, insulation and external heating. Ensure that all insulation and external heating elements are replaced as soon as possible if they are ever removed for inspection or repair. Regularly check all steam heating loops to be certain that they are properly installed and correctly operating.
  - Conduct routine external temperature scans to look for cold spots. Add insulation or external heating where required.
- **Elemental carbon (soot)**
  - Always confirm stoichiometry when the reaction furnace is being fired on a fuel gas stream or when any inline heaters (SRU reheaters or TGU burners) are initially being restarted with fuel gas. Stoichiometry checks involve measuring excess oxygen as an indication of excess stoichiometry operation (a portable fuel-cell-style oxygen analyzer is recommended for this service) and directly measuring process gas soot using various simple filter tests. **Note:** Damaged burners or poorly designed or operated burners can result in poor mixing and create multiple stoichiometry zones within the same burner, resulting in simultaneous soot and excess oxygen measurements.
  - Minimize baseline hydrocarbon content, along with the frequency and severity of hydrocarbon spikes in the acid gas and SWS gas streams, by optimizing the design and operation of the amine and SWS units. Detailed recommendations for minimizing hydrocarbons in these two units are available in literature.
  - Conduct sulfur wash procedures to remove soot from catalyst beds, where applicable. These procedures are best applied shortly after the soot has been created (i.e., within days or weeks), since experience has indicated that the soot can agglomerate and harden over time, making it harder to remove.
- **Iron corrosion products**
  - Prevent corrosion by using the detailed recommendations presented in the Corrosion section.
- **Alumina fines**
  - Conduct a preliminary removal of any visible dust after catalyst/refractory installation through vacuuming and sweeping of the affected vessels.
  - Prior to restarting a plant after a turnaround involving refractory or catalyst changes, conduct a thorough dust blow procedure. This involves using the sulfur plant air blower to blow dust out of the affected vessel and into the atmosphere (or to a dust collection device). The dust blow procedure is usually done vessel by vessel, with vessels reconnected to the next downstream vessel as they are cleaned. An exact procedure depends on the ease and ability of creating various breakpoints in the process and should be combined with buttoning-up steps for the various vessels after they have been entered during turnaround. The dust blow procedure has the additional benefit of removing all other lightweight contaminants, such as loose corrosion scale, soot and other light debris.
- **Ammonia salts**
  - Keep ammonia-containing SWS streams at or above 85°C (185°F) prior to entering the reaction furnace.
  - Ensure good reaction furnace ammonia destruction by maintaining furnace temperatures at or above 1,250°C (2,282°F). This can be achieved by various methods, including acid gas bypass designs, oxygen enrichment, feed gas preheating and fuel gas co-firing.
  - Properly tune acid gas-fired reheaters to avoid SO_3 formation. This should involve metering checks and analytical checks to confirm stoichiometry.

Part 2. Part 2—which will focus on temperature excursions, process fluid (gas/liquid) releases and explosions—will be published in the November issue. HP

NOTE

This article was first presented at the Laurance Reid Gas Conditioning Conference in Norman, Oklahoma, in February 2022.

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A system approach to mitigating corrosion under insulation

Industrial facilities employ a variety of metal piping and equipment that require insulation to operate efficiently. When corrosion occurs underneath insulation on this equipment, it can remain hidden for years, potentially leading to serious consequences. As moisture is the de facto contributor to corrosion for pipes running from –4°C–149°C, or that cycle in temperature within this range, protecting against water infiltration and the damage it poses to covered pipes is essential.[1]

Safeguarding piping and equipment against corrosion under insulation (CUI) may include multiple lines of defense against moisture intrusion. These defense measures include:

- Coating the pipe with a high-quality, water impermeable coating like paint, mastic, gel or vapor retarder
- Specifying an impermeable, non-absorptive insulating material
- Using proper insulation accessories to protect the system from moisture ingress, including joint sealers, adhesives and metal jacketing.

While these strategies comprise the infrastructure of an effective system, they are contingent upon correct installation to perform properly. In addition, an inspection and maintenance process should be established for the longevity of the system. This article will consider how a system approach can help mitigate the risk of CUI and contribute to the performance and longevity of piping and equipment.

Calculating the cost of CUI.

A study by NACE International estimated that the annual global cost of corrosion in 2013 was about $2.5 T, or 3.4% of the global GDP.[1] However, the same report also found that savings of 15%–35% (or $375 B–$875 B) could be made by a more comprehensive employment of already known corrosion mitigation practices. Similarly, a study from 2019 indicated that 40%–60% of pipeline repair costs are caused by CUI.[2]

Beyond the costs of unexpected downtime and unintended repairs, corrosion can present a safety hazard. In recent years, industrial incidents around the world have occurred where pipes or equipment failed following the development of corrosion (FIG. 1).[3,4,5]

Understanding CUI.

Corrosion refers to the deterioration of a material (typically a metal) into a more chemically stable form of itself via chemical or electrochemical reactions with its environment. One of the most common forms of corrosion specifically affects carbon steel, where oxygen reacts with iron to form iron oxide. In this example, one area of a metal surface (the anode) gives up electrons to another area of a metal surface (the cathode). This transfer of electrons is enabled by the presence of a conducting solution (an electrolyte) in the form of water. Oxygen that is present will chemically react with the anode as it gives up its electrons, leaving behind iron oxide (rust) on the surface of the anode.

CUI develops when moisture penetrates an insulation system and encounters the surface of metal piping or equipment, leading to corrosion. The consequences of CUI include unexpected and costly repairs and downtime, damage to expensive equipment and an increased potential for leaks. Depending on the extent of corrosion and the nature of the facility, CUI can lead to unexpected process system failures, piping failures, fires, explosions and employee injury or death.

Three risk factors that can cause or exacerbate the development of CUI are the presence of moisture, the chemical nature of the moisture present and the process temperature of the piping or equipment. Oxygen is also a key ingredient for corrosion; however, it is almost always readily found in any environment, whether in the air or dissolved in liquid moisture.

Moisture contacting the outer surface of a pipe is a key ingredient for corrosion to develop, as it serves as an electrolyte for electrochemical processes to occur. In an industrial setting, moisture can come from a range of sources, including natural precipitation, cleaning activities in the form of wash downs, and facility elements such as process leaks, deluge systems, cooling tower drift and sprinklers. Often, insulation systems rely on external vapor barriers or jacketings to help prevent moisture ingress from occurring. However, these barriers can become compromised due to poor installation and/or mechanical damage.[6]

Once present, the chemical nature of the liquid becomes important. Moisture that contains dissolved ions from salt, pollutants or insulation materials can lead to more aggressive rates of corrosion. This is because strengthening the acidity, alkalinity or salt content of water can increase the strength of the electrolyte in the corrosive reactions taking place.

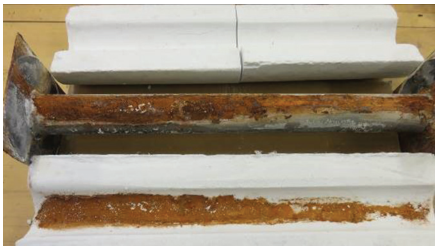

FIG. 1. Corrosion under insulation can be a hidden threat that develops out of sight when moisture penetrates an insulating system.

FIG. 2. The proprietary system[a] combines cellular glass insulation with a low-viscosity sealant and utilizes the impermeability of the insulation to establish a vapor barrier that moisture cannot pass through.

The operating temperature of piping or equipment can also influence the rate of corrosion. In general, the rate of corrosion will increase with the process temperature, as electrochemical reactions typically occur faster at higher temperatures. Pipes are considered at risk for corrosion at temperatures where liquid water can contact the metal surface, which can be roughly viewed as –4°C–149°C. Above these temperatures, moisture that penetrates the insulation system tends to evaporate before reaching the surface of the pipe. However, even these pipes can be at risk for CUI during temperature cycling periods or during any shutdown and restart procedures when moisture that has been forced away from the pipe is allowed to settle and rest against it.

Pipes operating at below ambient temperatures also face risk of moisture intrusion due to different mechanisms. In these systems, vapor drive from ambient air can force water vapor towards cold pipes, which then condenses into liquid moisture. If permeable insulations are used and existing vapor barriers become compromised, water can quickly build up along the cold pipe surface in the form of condensation, creating an environment for CUI to take place. Below roughly –4°C, a pipe may be considered out of this range, as liquid moisture will freeze into solid ice. However, like hot systems, these pipes can become at risk for corrosion if they experience frequent temperature cycling or system shutdowns as part of routine maintenance activities, where ice can thaw and once again act as an electrolyte to the system.

Signs of a problem. A Houston, Texas-based engineering consultant who formerly served as CUI track chair for NACE has seen a variety of corrosion situations in a career spanning more than four decades. According to the engineer, an early sign of moisture ingress for cold and cryogenic insulation is excessive condensation on the system jacketing's surface. Excessive condensation is the first fail test. Surface condensation caused by a reduced surface temperature is indicative of increased heat transfer due to wet insulation. Eventually, an ice ball will form on the metal jacketing, leading to total insulation failure. The potential presence of moisture within the system can also be a concern because it may indicate that CUI is potentially developing hidden from plain view.

System strategies for mitigating CUI. Early attention to warning signs is essential to address the problem and reduce further damage. Three primary strategies for mitigating CUI are keeping water out of the insulation, changing the chemistry of any moisture that enters the system and providing a dedicated way out for any moisture that does get into a system.

Thoughtful selection and proper installation of an insulation system can help mitigate the development of corrosion under insulation and the problems it presents. Because moisture poses a damage risk to an insulated system, vapor retarders are commonly used alongside insulation materials to help impede moisture infiltration. While effective when executed correctly, vapor barriers can be difficult to properly install and are vulnerable to incidental damage and perforation, especially if applied on top of a permeable insulation.

Pipe coatings are another solution that can be used to help prevent moisture from encountering a metal pipe. These coatings may be applied along the surface of the pipe underneath the insulation to provide an extra line of defense against any moisture that makes its way into the system.

Insulation use in mitigating CUI. As noted earlier, mitigating CUI requires a system approach that goes beyond insulation to consider the right pipe material, and appropriate and properly designed claddings, coatings and non-permeable insulation. Establishing a regular inspection and maintenance program is also essential. Beyond the insulating material, the insulation system includes adhesives and sealants, external coatings or claddings, and accessories.

Beyond ensuring a material will not absorb or retain moisture, specifying engineers should consider an insulation material's performance and dimensional stability in the needed temperature range. The material should also lack any chemistry that could increase acidity and the shedding of chloride ions (**FIG. 2**).

A material like closed-cell cellular glass insulation can address each performance aspect. Impermeable to water vapor and liquids, cellular glass insulation does not wick, retain or absorb moisture, including hydrocarbon-based liquids. The insulating material is dimensionally stable across a wide temperature range and will not warp or compress. Its glass composition provides an inert chemistry that is also low on leachable chlorides, much like a beaker used in a laboratory. The insulation can also be used with a range of materials and multiple types of accessories in a larger system. This type of insulating material has been incorporated into sealed systems designed to keep moisture from entering the insulation or reaching the pipe.

Detailing a sealed system. An example of a system designed to keep water out[a] combines cellular glass insulation

with a low-viscosity sealant that has a wide service temperature range and cures at ambient temperatures. This system utilizes the impermeability of the insulation to establish a vapor barrier that moisture cannot pass through. The paired sealant is then used at all joints, penetrations and terminations to ensure all gaps between the insulation are sealed against moisture ingress, protecting the pipe underneath from encountering the liquid water needed for corrosion (**FIG. 3**).

Sealed insulation systems of this nature can be used in a range of industrial applications where CUI is a concern. They are commonly used on below-ambient and cycling systems where insulated pipes are cold and face a high vapor drive. However, they are also relevant on above-ambient systems where physical moisture ingress is anticipated, as the elevated temperatures associated with these lines can lead to faster rates of corrosion development should water penetration occur.

Testing insulating systems. A series of tests were conducted to examine how well the proprietary technology[a] can be used to protect pipes in extreme conditions. The experiments evaluated a sealed system comprised of cellular glass insulation and a low-viscosity, neutral cure sealant. In the testing, pipes were protected by this system for 28 d in accordance with a modified ASTM B117 Standard Practice for Operating Salt Spray (Fog) Apparatus.[7,8] Pipes faced one of two situational challenges: salt rain, or salt fog and rain.

In the first arrangement, pipes experienced an ambient temperature of 21°C with a rain solution of 5% salt sprayed every 20 min. In the second, an ambient temperature of 35°C was combined with a constant fog containing 5% salt along with a 5% salt solution sprayed every 20 min.

Unprotected pipes were visibly and extensively corroded by the end of the testing. However, piping with the sealed insulation system applied were removed at the conclusion of the test with no visible signs of corrosion.

Performance in the field: Comparing two insulating approaches. The use of a closed-cell material can support an insulating system's longevity. Not all closed-cell materials perform the same and the type of closed-cell material used can also make a difference. The author's

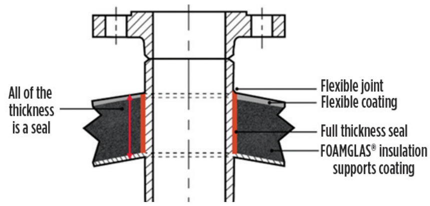

FIG. 3. A correctly applied insulating system using impermeable cellular glass insulation and a low-viscosity sealant can help mitigate CUI by combating moisture ingress.

colleague described two insulation systems near a busy shipping channel in Houston's humid climate. One piping system was insulated with polyisocyanurate insulation (PIR) and the other was insulated with cellular glass insulation. According to the engineer, it was possible after 5 yr to see white ice forming on the PIR surface and the system had to be replaced after 7 yr. After 15 yr, the cellular glass showed no signs of sweating. The engineer has worked on projects where the cellular glass insulation was still performing after 40 yr.

When it comes to insulating pipes in hydrocarbon processing applications, there is no silver bullet, and a system approach is required to safeguard against the hazards moisture presents. Facilities should consider the risks CUI poses and take steps to mitigate its occurrence by correctly installing, designing and maintaining an insulation system. Using an impermeable insulation, like cellular glass insulation, as one part of the insulation system can help control the development of CUI. HP

NOTES

[a] FOAMGLAS® Insulation Sealed System

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Accelerating the transition to renewable fuels

The global push to neutralize carbon-based greenhouse gas (GHG) emissions by 2050 not only holds great promise for the future of the planet, but it also stands to create millions of jobs, spur rapid growth and drive technological innovation. Businesses in every industry around the world have rolled out environmental and social responsibility (ESR) initiatives, often with bold plans to decarbonize their operations in line with the global 2050 net-zero goal, although these plans differ in scope and strategy. Since the transportation industry accounts for roughly 30% of all GHGs in the U.S.,[1] new kinds of renewable fuels made from organic sources (such as plant oils or animal waste) are expected to play a leading role in the transition to an environmentally sustainable economy.

How policy and technology changes are shaping biofuels' future. Biofuels are not new. At 17.5 Bgpy, ethanol, which is made from corn and mixed with gasoline, is the most-produced alternative transportation fuel in the U.S.[2] Developed in the 1970s and put into wide use by the 1980s,[3] its advantages and cost-related drawbacks are well understood. Today's new green fuels are sourced from agricultural waste and crops that are chemically identical to traditional fossil fuel-based products; however, they provide better performance with a smaller carbon footprint.

Advances in automation technologies make it more feasible to convert previously unusable raw materials (e.g., switchgrass and used cooking grease) into feedstocks that can be processed into high-quality combustible fuels that compete with fossil-based products like jet fuel and automotive gasoline—as well as, increasingly, electric power and natural gas. Meanwhile, leaders in the airline, railroad and trucking sectors have begun powering their fleets with renewable fuels, all of which have created opportunities for savvy downstream operators to stay ahead of the curve.

Carbon intensity (CI) is the amount of GHG emissions per unit of transportation energy delivered during a fuel's "well-to-wheel" lifecycle—measured in grams of carbon dioxide (CO_2) equivalent per megajoule of energy. Waste-based biofuel feedstocks, such as used cooking oil, have lower CI scores than those that could be turned into an edible food source (e.g., corn). Other factors affecting CI include the distance from feedstock source to the processing facility, and the energy and GHG emissions required to process the fuel into a finished product.

Research shows that, depending on assumptions about future policies and societal norms, the decline in the share of hydrocarbons in the global energy system could be dramatic, especially with the corresponding rise in demand for renewable energy as the world increasingly electrifies. If the 2050 net-zero goal is met, then the share of hydrocarbons in primary energy streams could drop from around 85% in 2018 to between 20%–70%, with the share of renewable energy increasing to between 20%–60%.[4]

Government programs such as the European Green Party's Green New Deal and the European Union's Renewable Energy Directive (RED II) that sets the target for renewable consumption at 32% by 2030[5] are primary reasons why more refiners are exploring these new fuels today. The U.S. government currently offers federal tax credits[6] to biofuel refiners, and Canada, California and Oregon have implemented their own low-carbon fuel standards (LCFS), which use a system of incentives and penalties to encourage industries to meet CI goals in both the manufacture and use of renewable transportation fuels.[7]

How the market landscape is shifting. These policies have driven real changes in the market. Data from California shows that, as fossil-based ultra-low-sulfur diesel (ULSD) consumption decreased between 2011– 2020 and CI dropped along with it, renewable diesel and other biofuels more than made up the difference in supporting demand without effecting CI.[7] Biodiesel consumption worldwide has more than doubled over the last 10 yr to 682,000 bpd and is growing at more than 11%/yr.[8] Current market forecasts see global demand for renewable diesel on the rise through 2026 at beyond.[9]

The combination of government policies, corporate initiatives and recent breakthroughs in automation technology have turned more sustainable renewable fuels like green diesel and sustainable aviation fuel (SAF) into the fastest-growing alternative energy streams in the market. SAF, which produces up to 70% less carbon than fossil fuels, could effectively bridge current renewable technologies with future hybrid, electric or hydrogen-powered engine designs.

In February 2022, Singapore's civil aviation authority announced it would support the city-state's flagship carrier Singapore Airlines in buying SAF from ExxonMobil to fuel part of its passenger fleet.[10] Finnish oil refiner Neste Oyj will provide 1.25 MMl of SAF, which is mixed with refined jet fuel at ExxonMobil's facili-

ties in Singapore. This 1-yr pilot program is expected to reduce CO_2 emissions by about 2,500 metric t.

What leading refiners can do to seize the opportunity. The most pressing challenges for refiners in the global downstream oil and gas space are meeting key performance indicators (KPIs) while also maintaining the flexibility to handle different production processes, as well as ensuring equipment reliability with demanding feedstocks, following complex regulatory requirements to secure government subsidies, and advancing refiners' own corporate social responsibility and sustainability initiatives.

Ensuring feedstock flexibility and measurement certainty. Staying in the black while breaking ground on new renewable fuel plants and retrofitting others means that refiners must obtain the very best production yield possible, while meeting quality specifications. This requires highly accurate process measurements to calculate CI data, along with advanced analytics software to evaluate overall plant performance under varying feedstock scenarios.

Traditional level and flow measurement technologies are impacted by changing fluid properties and ambient conditions, which are unavoidable when processing animal fats, corn oil, recycled cooking oil or vegetable oil. Smart flow metering systems and level instrumentation that can handle different fluid properties in a wider range of environments make it easier to dependably meter fluid transfers and to report receipts, usage and shipments.

Optimizing yield and asset health in new processes. Average yields from the second-generation renewable diesel process depend on many operating factors. Having precise control over the complex processes inside a plant's reactors is key for avoiding over-cracking products and for meeting quality and emissions standards. Control directly affects reactor catalyst life, which is a major cost concern. Analytics software can identify optimum operating conditions for each feedstock type, and can also calculate ideal production targets and provide early warnings to potential issues so that operators can maximize diesel yield while also reducing waste disposal and streamlining maintenance.

Always a priority, equipment reliability is even more critical when processing highly corrosive biomass feedstocks. Asset health monitoring solutions (e.g., corrosion sensors installed on critical vessels) are more common, but corrosion data can be difficult to interpret and act upon. Wireless ultrasonic sensors with data historian software extend vital equipment life by enabling proactive maintenance well before workers' security lapses and production throughput can suffer from safety incidents and unplanned downtime.

Reporting to regulations, minus the headaches. While the renewable fuels market owes its continuing growth largely to government subsidy programs, these policies impose complex reporting rules that require licensors to store data in an agile, secure place that can serve a variety of functions. Renewable diesel plants must meet extensive federal and state reporting requirements. In North America, the U.S. Environmental Protection Agency (EPA) and the U.S. Internal Revenue Service (IRS) work with state agencies to administer tax incentive programs that require refiners to gather extensive data from many sources, such as reconciled pathways, contracts, invoices, transportation and custody chain documentation. Penalties and fines are enforced for reporting errors.

Aggregating the data in a central repository is common, but companies often find themselves drowning in swamps of data that they cannot use. Companies need a data management strategy that will enable them to connect to all sources—as well as make the data useful in the right context, whether it is operational decisions, regulatory reporting, trend analysis or whatever is needed.

The authors' company's proprietary digital ecosystem platform[a] features data lake tools that help aggregate, historicize and organize information required for reports and analytics, as well as for integrated visualization tools and KPI dashboards—all with real-time secure remote access. This technology makes it possible to effectively automate the entire regulatory data gathering, analysis, visualization and reporting workflows, and provides the flexibility to accommodate future fuel standards and inevitably changing requirements, which is crucial in such a fast-evolving market.

Advancing refiners' sustainability initiatives. With the growing impact of decarbonization on socioeconomic priorities worldwide, tasks such as accurately tracking CI data, continuously monitoring and predicting emissions, maximizing energy efficiency, identifying waste, and measuring the impact of operational decisions have never been more imperative for downstream manufacturers.

Renewable diesel plants are large consumers of electric power and of hydrogen, which involves complicated energy-intensive process interactions. Lower CI numbers mean more LCFS credits, but gathering and calculating the information accurately is complicated by varying feedstocks and plantwide energy consumption data, which is often only available after the fact in monthly reports. Fortunately, it is now possible for renewable diesel plants to maximize their CI credits by using energy management information systems (EMISs), powered by artificial intelligence, that can provide real-time energy performance data and reduce total site energy usage by up to 15%.

Two other areas where automation can help are pressure relief valve (PRV) monitoring and flare gas analysis. Locating the source, time and duration of releases from PRVs requires extensive hands-on work and data interpretation, but wireless pressure gauges, acoustic transmitters and analytical software can record and interpret PRV events, making it easier to find and seal leaks. Of course, fugitive emissions are a concern for many valve types in a refinery, which is why the authors' company's low-emissions valve seal packing systems are rigorously designed and tested to ensure that ambient conditions meet the U.S. EPA's 100-parts per million (ppm) concentration requirement.

Finally, all refineries flare vented gases into the atmosphere as a byproduct of normal operations. Precise measurement and analysis of the flare are critical to monitor emissions and ensure efficient combustion. Sophisticated instrumentation and control systems can detect precise changes in gas composition and can respond in real time to optimize combustion efficiency and keep emissions within targeted levels.

Key takeaways. Leading refiners have been preparing for the world to eventually phase out fossil fuels for years—not only because this is the socially responsible

thing to do, but because it also makes good business sense. Reducing emissions and optimizing energy consumption means achieving lower cost of operations and extracting greater value from resources. In some countries, producers are carving out 40%–60% of their refining capacity to produce green fuels. The implementation of new technology, software and analytics increases reliability, optimizes energy, lowers emissions and reduces the overall environmental impact.

Downstream operators are in a unique position to invest in these technologies and to get in on the ground floor as the transportation industry's transition to renewable fuels picks up momentum. Those who fully recognize the potential competitive advantage that automation can deliver could be the leaders in the renewable fuel market in the next decade and beyond. HP

NOTE

[a] Emerson Automation Solution's Plantweb digital ecosystem

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ASTM D5453 vs. D7039 and the importance of oxygen correction for B100 samples

The use of biodiesel is rapidly becoming more popular due to growing trends both inside and outside the petroleum industry. The U.S. Energy Information Administration's (EIA's) data shows that biodiesel production in the U.S. has increased by more than 100 MM gal/mos since 2011, with biodiesel making up 4% of total diesel consumption in 2016. The EIA forecasts biofuels production to increase between 18%–55% over the next 30 yr. Responding to the evolving industry and social landscape, many traditional refineries have begun to incorporate biodiesel into their finished products.

While biofuels typically contain low amounts of sulfur, they are still required to adhere to fuel quality compliance specifications either for use in vehicles or as a blending feed for traditional refinery fuels. As such, biorefineries must measure the sulfur in their product to ensure that it is below regulatory limits, typically less than 15 parts per million (ppm). Biofuel analysis can be challenging due to the variety of feedstocks and to changing sample compositions.

According to ASTM D6751-20a [Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels], there are several options for testing sulfur in biodiesel. ASTM D5453 is listed as the referee method, but D7039 may also be used. This article examines these methods in more detail, using data from the ASTM B100 Proficiency Testing Program (PTP), and discusses renewable diesel vs. biodiesel, as well as the importance and methodologies for oxygen correction.

ASTM B100 PTP overview. The ASTM B100 PTP allows biodiesel laboratories to improve their testing performances by comparing their biodiesel test results with other laboratories. The statistical analysis also provides a valuable tool to assess test method performance on a particular matrix type and allows comparison between two or more test methods that measure the same property. For the B100 PTP, ASTM sends 1-gal samples out three times per year for analysis of approximately 24 biodiesel properties. This article will focus on sulfur analyses from 2018–2021, using ASTM D5453 and ASTM D7039. First, understanding the test methods is critical to interpreting the data presented.

ASTM D7039 (Monochromatic wavelength dispersive x-ray fluorescence). Monochromatic wavelength dispersive x-ray fluorescence (MWDXRF) is a subset of WDXRF that utilizes similar principles. Rather than using filters or traditional crystals that are flat or singly curved, MWDXRF incorporates doubly curved crystal (DCC) optics to provide a focused, monochromatic excitation x-ray beam to excite the sample. A second DCC optic is used to collect the sulfur signal and focus it onto the detector. This modified methodology delivers a signal-to-background ratio that is 10 times more precise than traditional WDXRF, which improves method precision and limit of detection (**FIG. 1**).

ASTM D5453: MWDXRF. In ultraviolet fluorescence (UVF) technology, a hydrocarbon sample is either directly injected into a high-temperature (1,000°C) combustion furnace or placed in a sample boat that is cooled and then injected into the combustion furnace. The sample is combusted in the tube, and sulfur is oxidized to sulfur dioxide (SO_2) in the oxygen-rich atmosphere. A membrane dryer removes water produced during the sample combustion, and the sample combustion gases are exposed to ultraviolet (UV) light. SO_2 is excited (SO_2^*), and the re-

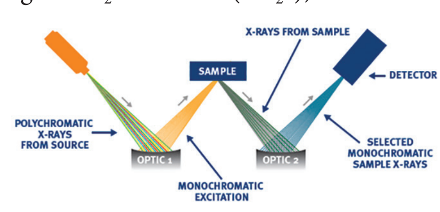

FIG. 1. MWDXRF delivers a signal-to-background ratio that is 10 times more precise than traditional WDXRF, which improves method precision and limit of detection.

TABLE 1. ASTM test method scope and precision equations

Method	Scope, ppm	Repeatability, ppm*	Reproducibility, ppm*
D5453	1–400	$0.1788 \cdot X^{0.75}$	$0.5797 \cdot X^{0.75}$
	400–8,000	$0.02902 \cdot X$	$0.1267 \cdot X$
D7039	3.2–2,822	$0.4998 \cdot X^{0.54}$	$0.7384 \cdot X^{0.54}$

* Where X is the average of the two results

sulting fluorescence that is emitted from the SO_2^* as it returns to the stable state is detected by a photomultiplier tube. The resulting signal is a measure of the sulfur contained in the sample.

ASTM test method scope and precision. Within the ASTM test method, the scope defines the test method parameters, including matrices of interest and ranges of applicability. This scope is defined by an interlaboratory study (ILS), which also determines the precision (repeatability and reproducibility) of the test method. (**Note:** This is a separate study from the PTP). Both ASTM D7039 and D5453 include diesel, biodiesel and biodiesel blends—see **TABLE 1** for the applicable range of these test methods, along with precision equations for each test method.

The ILS study is a discrete study used to define the repeatability and reproducibility of the test method. The advantage of these studies is that they cover multiple sample matrices spanning the entire concentration of the test method. The disadvantage is that these studies are from a discrete point in time, and they typically do not provide in-depth data on a particular sample type. For this information, it is better to look at ongoing ASTM PTP studies, which are organized around a particular sample type, rather than around sample properties (test methods). By filtering multiple PTP test cycles for a sample property, it is possible to get in-depth looks at particular test methods.

ASTM defines precision in terms of repeatability and reproducibility:

- Repeatability is the difference between successive results obtained by the same operator in the same laboratory with the same apparatus and the same test method under constant operating conditions on identical test material.
  - A lower repeatability value correlates to a better level of precision and to a higher likelihood of obtaining the same or similar test results over multiple measurements of different aliquots of the same sample.
- Reproducibility is the difference between two single and independent results obtained by different operators who are applying the same test method in different laboratories, using different apparatus on identical test material.
  - A lower reproducibility value correlates to a better level of

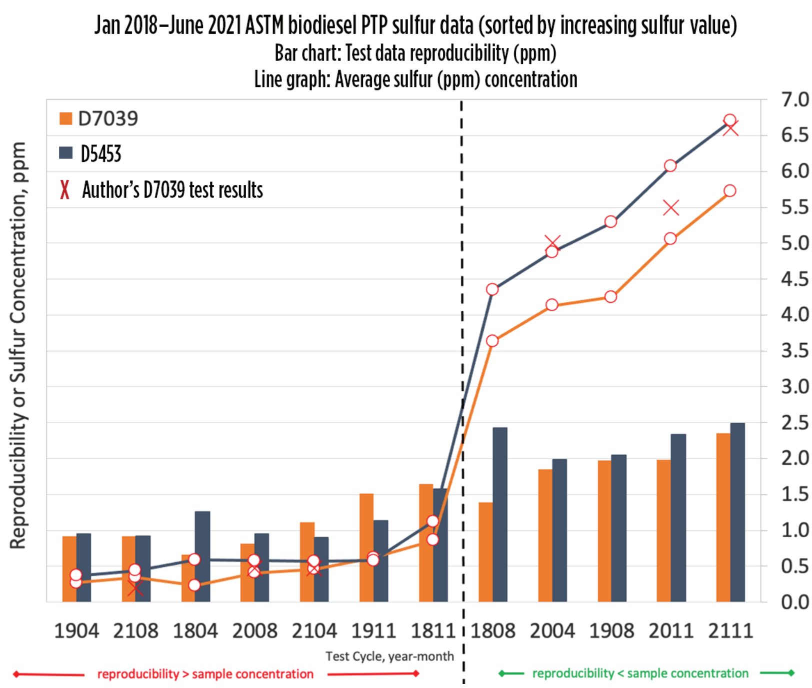

FIG. 2. ASTM B100 PTP sulfur data, January 2018–June 2021.

TABLE 2. ASTM B100 PTP sulfur concentration and PTP reproducibility, ppm (blue text = sulfur concentration is below method scope; red text = reproducibility is greater than the sample concentration)

Program cycle sample date	PTP average sulfur concentration		Author's D7039 sulfur results*	PTP reproducibility	
	D5453	D7039		D5453	D7039
2019 (April)	0.37	0.27		0.95	0.92
2021 (August)	0.44	0.35	0.2	0.92	0.92
2018 (April)	0.59	0.23		1.26	0.66
2020 (August)	0.58	0.41	0.5	0.95	0.82
2021 (April)	0.57	0.46	0.5	0.9	1.11
2019 (November)	0.58	0.62		1.14	1.51
2018 (November)	1.12	0.86		1.58	1.65
2018 (August)	4.35	3.63		2.43	1.39
2020 (April)	4.87	4.13	5	1.99	1.85
2019 (August)	5.29	4.25		2.05	1.97
2020 (November)	6.07	5.05	5.5	2.34	1.99
2021 (November)	6.7	5.72	6.6	2.49	2.35

* The author's company did not join B100 PTP until January 2020.

precision, which can minimize risks (such as incurring regulatory fines and contract disputes) that can result from inaccurate reporting.

Next, we will look at sulfur data from an ASTM biodiesel (B100) PTP.

ASTM B100 PTP results. There were 12 biodiesel program cycles (or data points) from 2018–2021. On average, there are three times as many D5453 participants vs. D7039 participants—although, if participants are submitting data using both sulfur methods, this value may be skewed. Only one result is submitted per laboratory for each test method; therefore, the program statistics cannot include sulfur repeatability, thus limiting this discussion to sulfur reproducibility. The sulfur data and statistics can be summarized as follows:

- The average sulfur concentration ranged from 0.27 ppm–6.7 ppm (FIG. 2, TABLE 2).
- Half of the sulfur data points (six for D5453 and seven for D7039) are below the test method scopes (TABLE 2).
- Approximately 58% of the data (0.27 ppm–1.12 ppm sulfur) has a lower sulfur concentration than its associated reproducibility (FIG. 2, TABLE 2).
- Of the remaining 42% of data (FIG. 2, TABLE 2), D7039 has consistently equal or better reproducibility and is biased lower than D5453.
- The author's D7039 reported results with sulfur concentrations within the D7039 method scope (as shown in the FIG. 2 red Xs right of the dotted line, and in TABLE 2 results below the dotted line) were closer to the average D5453 sulfur concentration than the rest of the D7039 data.

What does all this mean? In short, this data snapshot suggests the following:

1. Neither D5453 nor D7039 are suitable for B100 samples ≤ 1 ppm sulfur.
2. D7039 has equivalent or better precision than D5453 for B100 samples within the D7039 method scope.
3. There is some evidence to suggest that PTP D7039 method users may not be correcting for oxygen matrix effects.

It is not surprising that the PTP reproducibility is poor for B100 samples ≤ 1 ppm sulfur, as this concentration range is at or below the lower limit of both methods. This is because the lower limit of an ASTM method is based on the precision of the ILS data (it is not just based on the lowest concentration in the ILS). While D7039 has equivalent or better precision than D5453 for B100 samples within the D7039 method scope, it would have been interesting to see the reproducibility statistics for PTP data in the > 1 ppm–3.5 ppm sulfur range. More data within this range would have solidified whether D7039 was equivalent or better than D5453, as the lower limit for D7039 is 3.2 ppm.

Lastly, there is limited evidence suggesting that PTP participants using D7039 may not be correcting for oxygen matrix effects.

TABLE 3. Oxygen correction table for sulfur in biodiesel on a mineral oil calibration (Source: ASTM D7039 Table 2)

Oxygen, wt%	0	1	2	3	4	5	6	7	8	9
0%	1	1.0174	1.0348	10522	1.0696	1.0870	1.1044	1.1218	1.1392	1.1566
10%	1.174	1.1914	1.2088	1.2262	1.2436	1.261	1.2784	1.2958	1.3132	1.3306

Note: Determine the correction factor by finding the known oxygen content of the test specimen (e.g., 11 wt%) as the sum of the value in the first column and the value in the first row (e.g., 11 = 10 + 1). The intersection of these two values is the correction factor (e.g., 1.1914).

Renewable diesel vs. biodiesel and oxygen effects on x-ray fluorescence (XRF). Biofuels are any liquid fuels made from renewable biomass, including ethanol, biodiesel and renewable diesel. While the terms "renewable diesel" and "biodiesel" are sometimes used interchangeably, they are actually different. According to the Alternative Fuels Data Center, renewable diesel is a biomass-derived hydrocarbon that meets ASTM D975 specifications for diesel fuel, and is produced through various processes such as hydrotreating, gasification, pyrolysis, and other biochemical and thermochemical technologies. Biodiesel is a mono-alkyl ester that meets ASTM D6751 specifications for biodiesel and is produced via transesterification.

Another difference between renewable diesel and biodiesel is that biodiesel contains oxygen, typically around 10 wt%–12 wt%, whereas finished renewable diesel does not contain oxygen and is considered a drop-in product. Feedstocks for biodiesel and renewable diesel may contain varying amounts of oxygen, depending on the type of feedstock and where in the process the intermediate stream has been sampled.

From an ease-of-use standpoint, drop-in products are easy to measure using XRF, as no additional precautions are needed, and the sample can be measured on a typical hydrocarbon calibration. For diesel-like matrices, samples above 2.5% oxygen must be addressed through matrix-matched calibration standards or correction factors. The high oxygen content in these samples leads to significant absorption of sulfur Kα fluorescence, and, if uncorrected, to low sulfur results (see Section 5.2 in D7039).

Matrix matching uses calibration standards with the same or similar elemental composition as the samples being measured. For biodiesels, it is possible to make or obtain calibration standards in a biodiesel matrix. However, it should be noted that true biodiesel blanks are difficult to find, as they are usually sulfur contaminated. Consider using methyl oleate or octanol for a biodiesel blank, instead of the biodiesel blank that comes in the calibration set. Chances are it is not blank and may cause issues when measuring low-concentration samples.

For oxygenated feedstocks or samples with varying oxygen content, it may be advantageous to use correction factors instead. ASTM D7039 Table 2 (**TABLE 3**) has correction factors for varying amounts of oxygen in biodiesel measured on a mineral oil calibration. The correction factor is applied by multiplying the uncorrected measured result by the correction factor to obtain the oxygen-corrected result. **Note:** The correction factors are limited to D7039-compliant MWDXRF systems, such as the author's company's proprietary analyzers[a]. Also, these correction factors can be used on these analyzers when in both 7039 and 2622 modes because the correction factors in **TABLE 3** are applied to the sulfur ppm values calculated from the total counts per second (cps) in 7039 mode or from net cps in 2622 mode (background counts are subtracted), at which time the basic analyzer geometry is identical.

Working through a couple of examples, consider two biodiesel samples containing 10 wt% oxygen measured on a mineral oil calibration:

- (uncorrected measured value) × (correction factor) = sulfur corrected value
- 1 ppm sulfur (uncorrected) × 1.1740 = 1.2 ppm sulfur (corrected)
- 10 ppm sulfur (uncorrected) × 1.1720 = 11.7 ppm sulfur (corrected).

Because the correction factors in **TABLE 3** are multiplicative, as the sulfur concentration increases, the difference between the oxygen corrected and uncorrected values is greater, which creates a widening of the gap between the measured value and the true value of the sample. A visual representation of this would look like the line graph in **FIG. 2**, wherein the average concentration difference between D5453 and D7039 widens as sulfur concentration increases.

To be clear, we do not know for certain if the bias between D7039 and D5453 is due to oxygen correction issues because D7039 PTP participants do not report their calibration matrix and method of oxygen correction. However, it can be surmised that this is at least part of the issue based on the red Xs in **FIG. 2.** These red Xs represent PTP samples measured at the author's company by using D7039, a mineral oil calibration and correcting the measurement result for 10 wt% oxygen. In this instance, it is known that the submitted results were corrected for oxygen, and it can be observed that, as the sulfur concentration increases, these results stay more consistent with the average D5453 sulfur concentration than the rest of the D7039 data. However, this theory is based on limited data from a single user, so it will be interesting to see if this trend continues as more data is collected. If there can be a takeaway from this, it is that it becomes increasingly important to correct for oxygen as the sulfur concentration increases.

Takeaways. Despite D5453 being the referee method for B100, data from the ASTM B100 PTP shows that D7039 has equivalent or better precision than D5453 for samples above 3 ppm. Data from this program also suggest that D7039 participants are not correcting for oxygen content, which not only becomes more important as sulfur concentration increases, but also may be responsible for the low sulfur bias relative to D5453 seen on the higher-concentration samples in this ongoing study.

Additionally, this article discussed the difference between renewable diesel and biodiesel, and how renewable diesel is a drop-in product that complies with the diesel specification and does not require the oxygen correction or matrix matching of biodiesel samples. HP

NOTE

[a] XOS's Sindie 7039, Sindie 2622 and Sindie+Cl analyzers

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A successful case of resid-to-propylene maximization using premium catalyst technology

The world has experienced profound changes throughout the global disruption created by the COVID-19 pandemic. The restrictions imposed on travel pushed most people to work remotely, with reduced domestic and international travel. Consequently, oil-derived transportation fuels demand was dramatically reduced, forcing refineries to adjust well-established operating strategies and product slates to maintain profitable operations.

Conversely, the demand for petrochemical products remained strong during the pandemic, which demonstrates the resilience of light olefins and chemicals products. As world markets recover and mobility restrictions lift, demand and margins for transportation fuels have returned to pre-pandemic levels, together with a robust petrochemical market.

Therefore, complex conversion units, including fluid catalytic cracking units (FCCUs), are ramping up feed rates and maximizing conversion of heavy feeds to satisfy this growing demand while adjusting the product slate for maximum profitability. In this environment, the role of premium catalytic solutions is of paramount importance to capture these opportunities and maximize value to the refiner.

The COVID-19 pandemic has also impacted the mid- and long-term view of the oil and gas industry. Many countries are adopting policies and regulations to accelerate the energy transition towards carbon neutrality, and society in general has a heightened environmental awareness. According to analysts, the industry may face a decline of global liquid products demand between 5 MMbpd and 25 MMbpd through to 2050, depending on the pace of the energy transition.[1]

This transition will not take place evenly across the globe, as mature markets are expected to transition faster than emerging regions. The decline of traditional transportation fuels consumption may lead to a structural low-margin scenario to conventional refining operations, which can be tackled with petrochemical integration and/or bio-feeds processing. The production of petrochemical feedstocks like propylene has a very robust profitability forecast given the expected strong demand vs. gasoline (**FIG. 1**).

In this environment, conversion units like FCCUs will play a key role in improving a refinery's profitability by converting low-cost heavy residual stocks into high-value propylene for chemicals production. Analysts are foreseeing a long-term structural margin benefit for those FCCUs incrementally increasing their LPG olefins yield compared to a conventional FCCU product slate (**FIG. 2**).

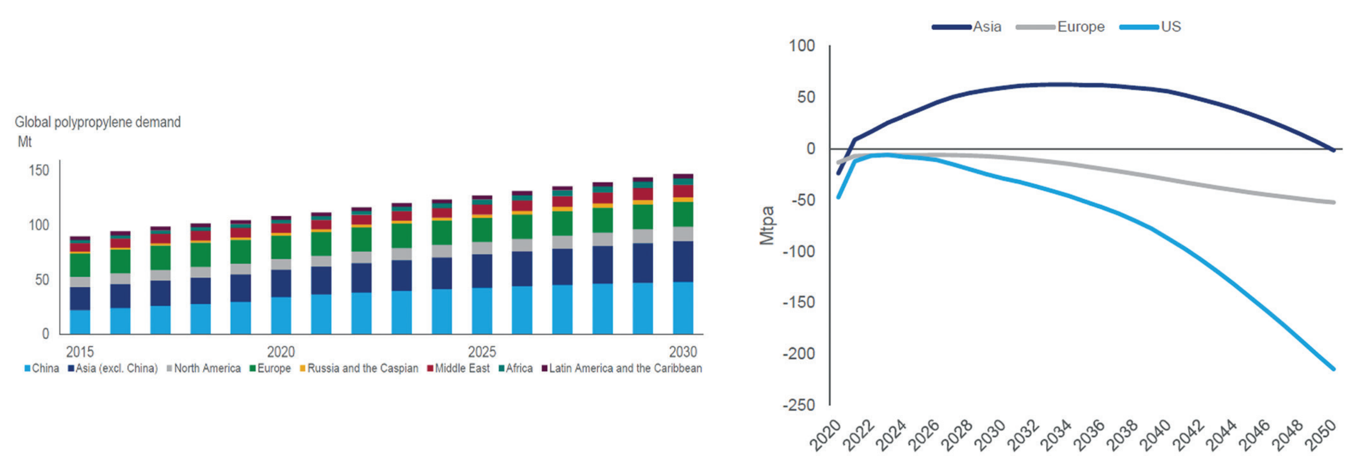

FIG. 1. Global polypropylene demand (left) vs. regional gasoline demand (right) forecast. Source: Wood Mackenzie.

To adjust the production towards light olefins, FCCUs typically require a suitable unit design and tailored catalyst technologies that deliver the required yield profile. Extensive use of ZSM-5-containing additives that crack olefin molecules from the gasoline range into liquefied petroleum gas (LPG)—as well as suitable Y-catalyst properties—are essential to meet the increased light olefins targets.

Several examples are available in literature that show how an FCCU can significantly increase its profitability by boosting its light olefins production.[2,3]

Studies show that refineries' propylene contribution to the global supply will continue to play a key role to satisfy the growing demand for many years to come,[4] as that contribution provides a clear cost-advantage vs. other potential dedicated technologies, as seen in **TABLE 1.**

This article details a successful case in which an RFCCU designed to process one of the heaviest residual feeds worldwide implemented a catalytic solution to significantly boost propylene yields and unit profitability by $15.2 MM/yr for the OQ Sohar Refinery in Oman.

TABLE 1. Economics of various propylene technologies in US$/MMt [propane dehydrogenation (PDH), methanol-to-propylene (MTP), coal-to-propylene (CTP)]

Process	Feedstock	Utilities and fixed	Capital cost	Total
FCC	565	53	40	658
PDH	584	200	125	909
MTP	510	110	106	726
Integrated CTP	–20	350	510	840

TABLE 2. Typical feed properties

SG	> 0.92 g/cm³
Nitrogen	> 1,500 ppm
Concarbon	> 6.5 wt%
Nickel	> 12 ppm
Vanadium	> 13 ppm

TABLE 3. Test on incumbent OQ catalyst vs. catalyst[b] in the absence of ZSM-5 additive

	Delta	
	Incumbent	**Catalyst[b]**
Conversion, wt% FF	Base	1.9
Hydrogen, wt% FF	Base	–0.06
Dry gas, wt% FF	Base	0.1
Propylene, wt% FF	Base	0.5
C_4= olefins, wt% FF	Base	0
Gasoline C_5-221°, wt% FF	Base	0.1
LCO, wt% FF	Base	–1.1
Bottoms, wt% FF	Base	–0.8
RON	Base	0.1
MON	Base	0.3
Coke, wt% FF	Base	Base

High resid-to-propylene catalytic solution implementation at the OQ Sohar RFCCU. OQ is the national energy company of Oman, wholly owned by the Sultanate of Oman. In addition to oil and gas exploration and production, the company also invests in power generation, energy transportation and infrastructure, oil refining and petrochemicals manufacturing.

Beginning in 1982 with a single refinery producing gasoline, the company that is now OQ has built up its downstream offerings and expanded the Sohar Refinery in 2006 with projects including the Sohar Refinery Improvement Project (SRIP) and the Liwa Plastics Industries Complex (LPIC). The complex now includes a refinery, aromatics plant, steam cracker and downstream polypropylene and polyethylene plants, making it one of the best-integrated refinery and petrochemical facility combinations in the world. The complex enjoys a strategic location and is able to deliver products to the east or west to capture market opportunities.

At the heart of the Sohar Refinery is the RFCCU, a primary conversion unit that converts heavy residue streams into high-value products like propylene and clean fuels. The RFCCU is a side-by-side (SBS) design with a two-stage regenerator, catalyst cooler, packed stripper and a vortex separation system (VSS) riser separator system, which allows them to process a high-Concarbon, high metals-content residual feedstock type. The RFCCU can process up to 79,000 bpd of one of the most challenging residual feeds in the industry (**TABLE 2**).

Propylene is one of the main economic drivers for OQ, requiring the RFCCU to operate at high severity with a well-designed catalyst system to boost light olefins production within unit constraints—which are typically regenerator temperature and air blower capacity—while keeping LPG flowrate at a maximum.

RFCCUs that process residue feedstocks face high intrinsic coke selectivity (high delta coke), which raises the regenerator temperature and lowers cat/oil ratio and conversion. Residue feedstock typically contains high levels of contaminant metals, which poison the catalyst and can lead to further increase of regenerator temperature and conversion loss. Maintaining catalyst activity in this environment is important, as an increased catalyst deactivation rate requires increased catalyst addition rates to keep inventory cracking activity.[5]

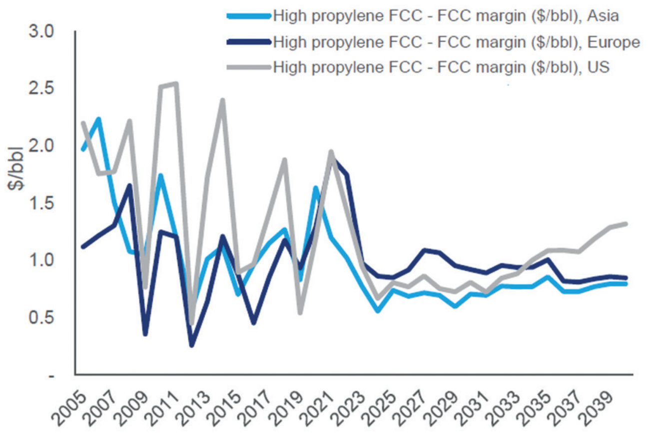

FIG. 2. Margin comparison between high-propylene FCC vs. conventional FCC. Source: Wood Mackenzie.

The proprietary catalyst platform[a] has led the low coke selectivity market, thanks to its performance demonstrated in more than 260 applications around the world since its commercial launch.

Examples of successful applications can be found in literature[1,2] and the catalyst platform RFCC catalysts have proven to deliver:

- Low delta coke in high metals applications
- Significant improvement in coke-to-bottoms performance
- Excellent activity and stability at high contaminant metals levels
- Increased C_3 and C_4 olefin yields
- Opportunities for refiners with the ability to process high-residue feedstock content.

The OQ RFCCU was using a premium coke selective from the authors' company's catalyst platform[a], along with a competitor's additive. To further optimize the unit profitability, the Sohar Refinery team conducted a catalyst selection process, targeting the following objectives:

- Maximum propylene (C_3=) production
- Maximum butylene in LPG
- Maximum gasoline octane barrels
- Minimum dry gas
- Minimum slurry yield.

The authors' company conducted an extensive internal testing program to determine the best catalytic solution to outperform the incumbent catalyst and additive in the unit based on the unit objectives and constraints.

Among all the solutions tested, a catalyst[b] in combination with a proprietary additive[c] was the catalytic solution that showed optimum performance.

A first step was made to improve the performance of the Y-zeolite based catalyst, support the lowest delta coke and gas make, increase better light olefins yields and set the stage for an improved efficiency for the ZSM-5 additive to further boost propylene production. The catalyst[b] is a combination of two synergistic technologies that are designed to provide optimum performance benefits. It integrates a proprietary zeolite stabilization in the latest catalyst offering[a] to further increase propylene precursors and LPG olefins, as well as decrease the delta coke to process heavier feed in the FCCU.

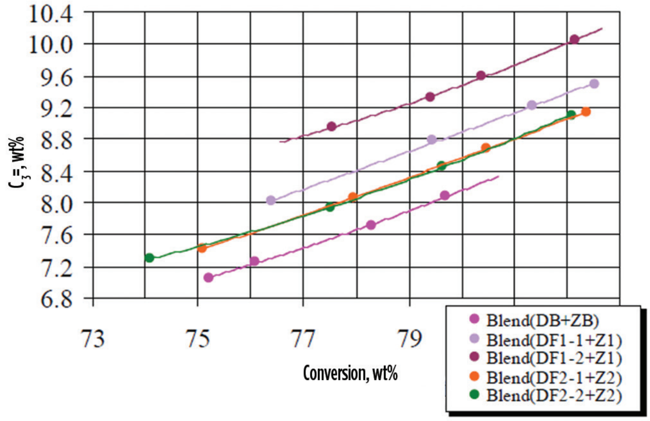

FIG. 3. Propylene yield of different catalysts at an FCC pilot plant (catalyst[b] + additive[c] labeled as DF1-2 + Z1).

As seen in **TABLE 3,** the move from incumbent technology to the new catalyst[b] showed a remarkable gain in conversion of 1.9 wt% with reduced bottoms, and a gain in propylene at constant coke yield.

The next step was to combine the performance of the proprietary catalyst with a high-activity ZSM-5 additive for a final optimal catalytic solution. A study using different amounts of ZSM-5 additive helped the refinery team to assess the potential propylene make for their RFCCU, as well as identify the optimum amount to be blended.

The additive[c] is one of the authors' company's high-activity, commercially available ZSM-5 additives designed for maximum propylene and butylene production, offering high activity per unit of additive.

The levels of ZSM-5 in conventional additives require significantly higher addition rates with the consequential increase in OPEX and manual handling activities. There is also potential to dilute the activity of the circulating catalyst inventory and subsequently deteriorate unit conversion.

As shown in **TABLE 4,** the inclusion of the high-activity additive[c] resulted in the expected improvement in propylene and butylenes at the expense of gasoline. As most of the cracked gasoline belongs to the olefinic light naphtha cut, the resulting gasoline octane improved due to aromatics concentration.

These identified performance benefits obtained in the authors' company's laboratories were subsequently confirmed in an external independent laboratory using a circulating riser pilot plant, which showed that the proposed catalytic solution outperformed all the other options tested (**FIG. 3**). Based on the pilot plant results, OQ proceeded with a trial in the industrial unit.

The increase in propylene yield was visible soon after both the incumbent fresh catalyst and the competitor additive solution were replaced, as can be seen in **FIG. 4.** This catalyst and additive combination, hereinafter named the novel catalyst

TABLE 4. Test on catalyst[b] at different levels of blended ZSM-5 additive

	Catalyst[b]	Catalyst[b] + 5% additive	Catalyst[b] + 10% additive	Catalyst[b] + 15% additive
Conversion, wt% FF	Base	Base	Base	Base
Ethene, wt% FF	Base	0.4	0.6	0.9
Dry gas, wt% FF	Base	0.4	0.6	0.9
Propylene, wt% FF	Base	4.2	5.5	6.6
C_4 olefins, wt% FF	Base	2.1	2.9	3.9
LPG olefinicity, %	Base	3.1	4.8	5.1
Gasoline C_5 at 221°C, wt% FF	Base	–8.1	–10.8	–13.5
LCO, wt% FF	Base	–0.1	–0.4	–0.6
Bottoms, wt% FF	Base	0.1	0.4	0.6
Coke, wt% FF	Base	0	0	–0.2
RON	Base	2.7	3.3	3.7
MON	Base	1.9	1.9	2.4

system, showed intrinsically enhanced selectivity to proylene and light olefins, while preserving bottoms cracking ability (**FIGS. 5** and **6**) with respect to previous catalyst[a] blended with a competitor ZSM-5 product.

An additional key performance variable is the ability to produce high-value propylene within wet gas compressor (WGC) limitations. When much higher severity is needed to push for more propylene, there is usually an intrinsic increase of dry gas make due to the enhanced thermal cracking. If this is coupled with non-suitable metals tolerance, it may easily limit the unit as low-value products increase the volumetric flow rather than propylene.

As can be seen in **FIG. 7,** the novel catalyst system, thanks to its higher crystal activity, was able to produce more propylene per unit of dry gas, which helped the Sohar Refinery to maximize the value of the flowrate coming into the WGC.

To validate both preliminary pilot plant testing and catalyst[d] monitoring, a comparison of normalized data was conducted to assess the performance of both catalyst periods at comparable conditions.

A test run was conducted in the industrial unit to compare both catalytic systems and subsequently normalized using a proprietary FCC SIM software[f] to compare cases at identical conditions. As can be seen in **TABLE 5,** the new catalytic system increased propylene by 0.9 wt% while improving bottoms cracking at similar coke make.

Due to this optimized catalyst system, OQ improved its position in the FCC industry as one of the best propylene makers processing one of the most challenging residual feedstocks, as can be seen in **FIG. 8.** A clear improvement in propylene, C_4 olefins and octane was achieved, while conversion levels remained unaltered.

The authors' company is continually developing new catalysts and propylene maximization additives. Its latest additive[g],

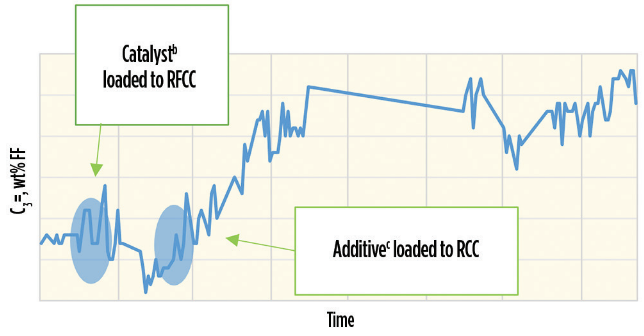

FIG. 4. Catalyst[d] propylene during the industrial trial period.

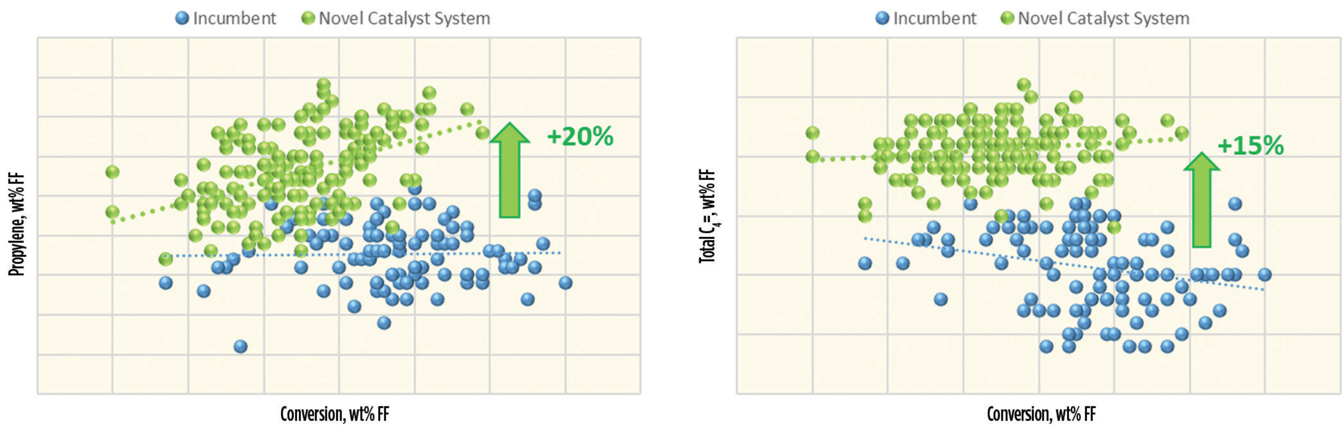

FIG. 5. Catalyst[d] light olefins yield at constant conversion.

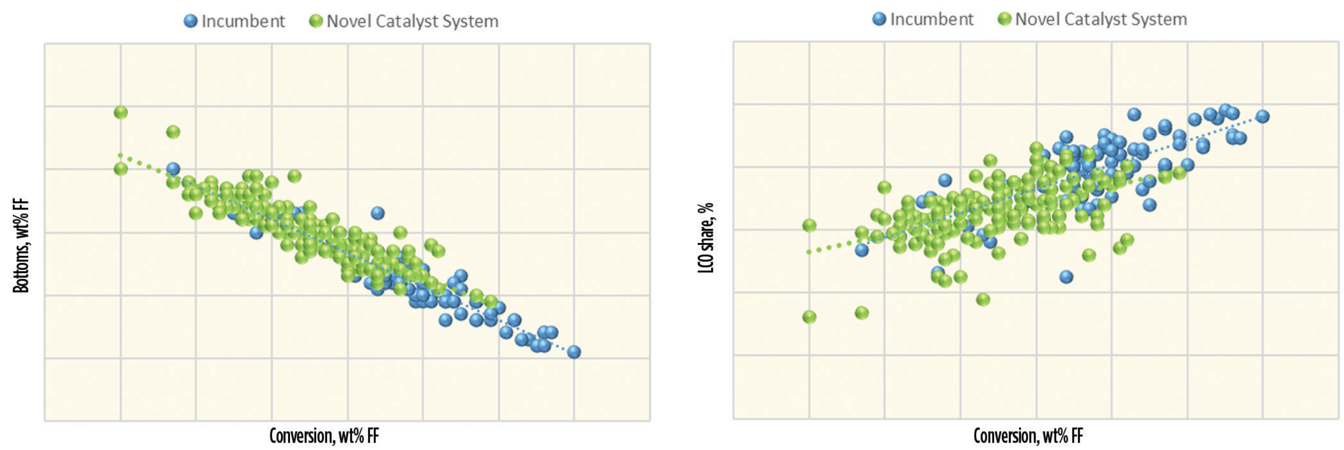

FIG. 6. Catalyst[d] bottoms yield and LCO-share at constant conversion.

at a constant additive level, shows higher light olefins yields compared to a leading additive[c] (FIG. 9).

Takeaways. OQ conducted a comprehensive and rigorous process to choose a new, higher performing catalytic system that would enable it to boost high-value propylene while reducing bottoms yields in its RFCCU.

The move from a previous-generation catalyst[a] to a new catalyst[b] combined with a high-activity additive[c] resulted in higher light olefins at much improved bottoms cracking, adding \$15.2 MM/yr in profitability.

Although this RFCCU is processing one of the most challenging residual streams in the industry, the authors' company's technologies helped position the Sohar Refinery as one of the biggest FCC propylene makers worldwide. The strong resid-to-propylene performance and the unique strategic location of OQ in Oman ensures a tremendous strong profitability position towards the new energy transition era for the FCCU. HP

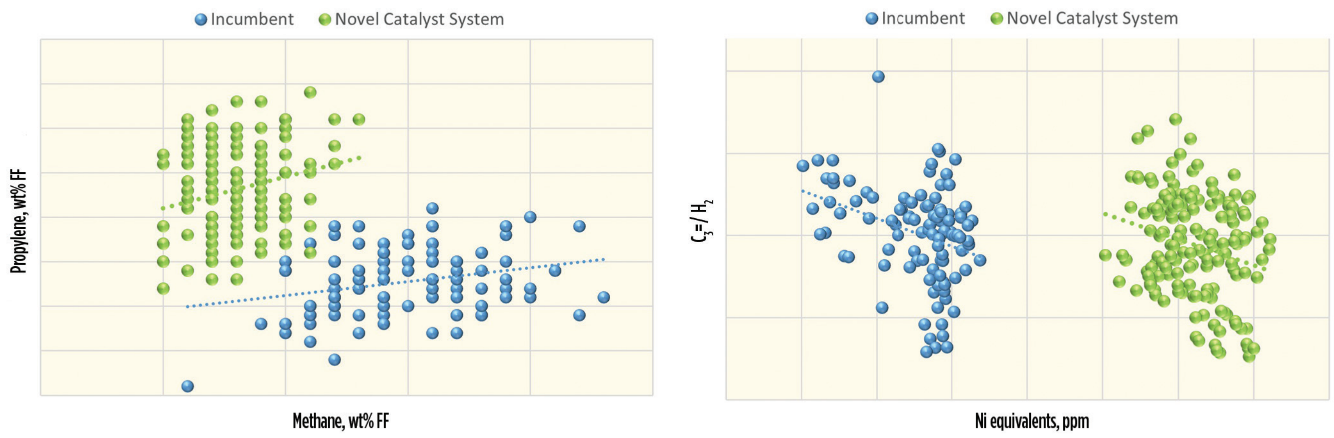

FIG. 7. Catalyst[d] propylene vs. hydrogen yields.

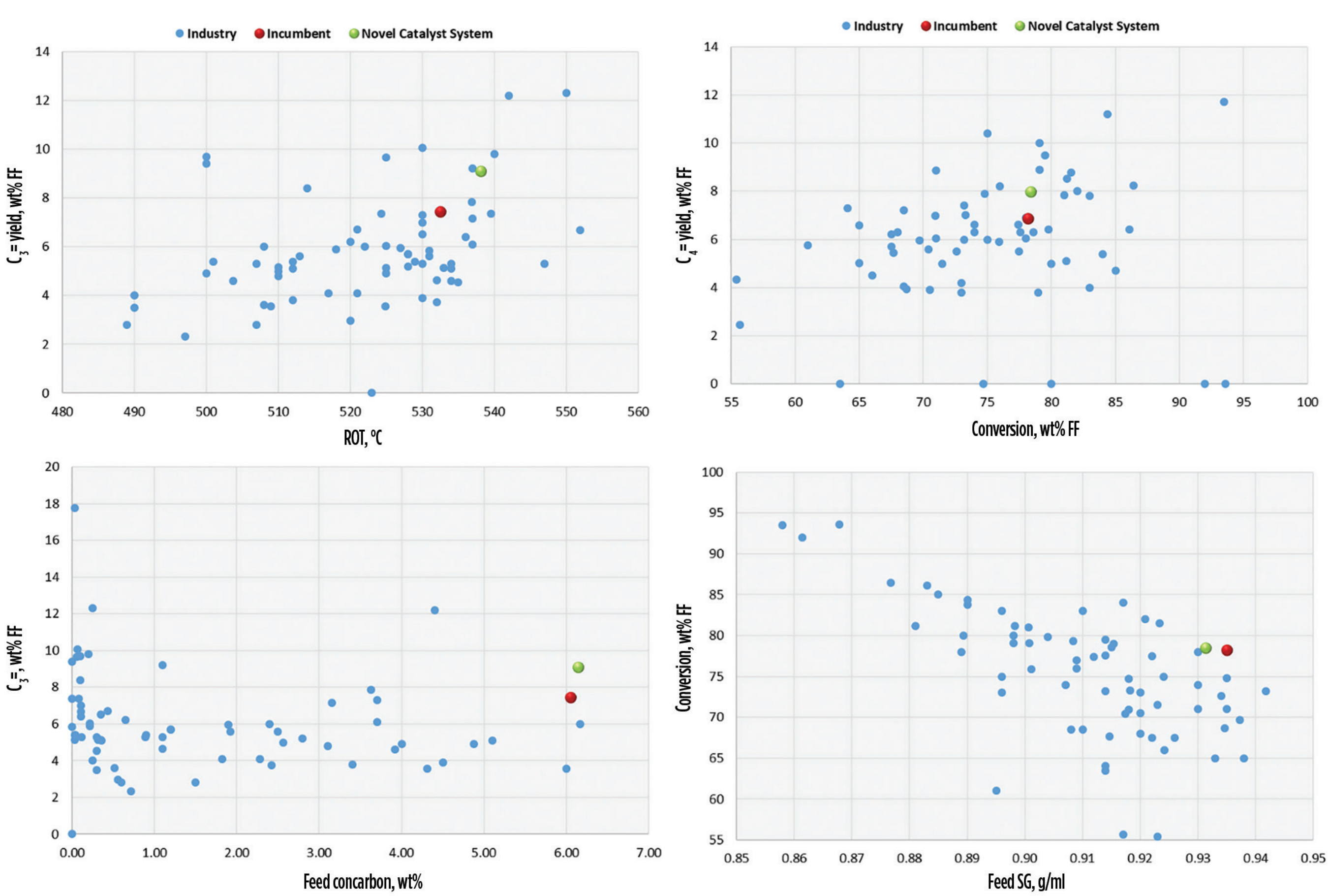

FIG. 8. OQ Sohar refinery RFCCU yields vs. industry.

TABLE 5. Industrial RFCC test runs and normalized yields for catalyst[b] + additive[c] catalytic system vs. incumbent

Test run normalized conditions		
Mass flow, metric t/hr	468	
ROT, °C	536	
Activity, wt%	72	
(Ni + V), ppm	10,714	
Unit yields, wt% FF	**Base case**	**Novel catalyst delta**
C_2–	Base	–0.1
C_3=	Base	0.9
LPG (ex. C_3=)	Base	0.4
C_5 standard naphtha	Base	–1.6
Standard cycle oil	Base	1.1
Standard FCC bottoms	Base	–0.8
Coke	Base	0.1

NOTES

[a] NEKTOR™ catalyst
[b] NEKTOR™ SRIP catalyst
[c] OlefinsUltra® MZ additive
[d] Ecat ACE™ catalyst
[f] KBC's FCC SIM software
[g] ZAVANTI® additive
[h] OlefinsUltra®

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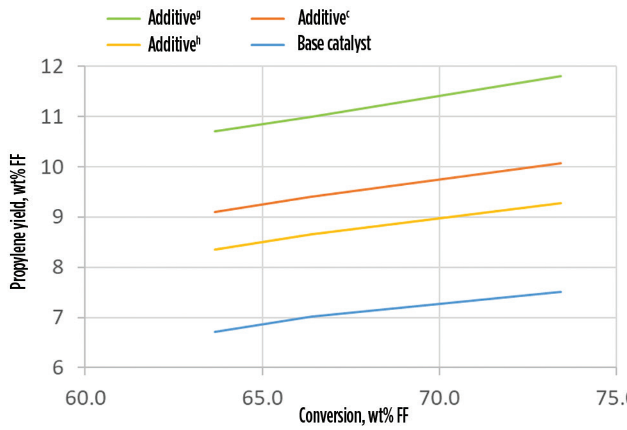

FIG. 9. Propylene yield comparison between the authors' company's different ZSM-5 additives.

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BEST AR/VR/AI TECHNOLOGY

Application of AI technologies and data-driven decision system in manufacturing for improving gasification operation and reliability, Reliance Industries Ltd.
Reliance developed a data-driven decision system, based on AI and explainable AI, to improve gasifier operation and reliability.

Factorial Kernel Dynamic Policy Programming (FKDPP), Yokogawa
Jointly developed by Yokogawa and the Nara Institute of Science and Technology, FKDPP is the first reinforcement learning-based AI system that can be utilized in plant management. It can be used to autonomously control chemical plant operations, ensuring product quality and energy savings.

Forecast 360™, Symphony Industrial AI
This all-inclusive process performance management solution combines process condition insights, performance metrics and process history to enable operators to self-optimize operations. This capability provides producers with assets that continuously adapt to demand, variations in supply, process deviations and human factors.

BEST ASSET MONITORING TECHNOLOGY

AMS Asset Monitor with AMS Machine Works Software v1.7, Emerson
This software is an online, continuous condition monitoring system that offers maintenance and reliability personnel an affordable, flexible solution for monitoring the health of a plant's assets.

Honeywell Forge Corrosion Advisor |Predict®-Crude, Honeywell
Predict®-Crude enables accurate quantification of corrosion due to naphthenic acid and sulfidic corrosion in crude refining operations.

Integrated Corrosion Management System for a Refinery and Petrochemical Complex, Reliance Industries Ltd.
Reliance has built an integrated system to monitor, mitigate and remedy corrosion within operations. This includes a team to monitor and inspect for corrosion, incorporating digital technologies for predictive maintenance and analysis on high-risk areas for corrosion, among others.

OpreX Asset Health Insights, Yokogawa
OpreX AHI is a cloud-based plant asset monitoring service that collects, refines, models and aggregates data from distributed assets. The service enables customers to easily model and manage data based on the plant hierarchy defined by the ISA-95 standard. It is equipped with AI and machine-learning analytics capabilities.

BEST ASSET RELIABILITY/ OPTIMIZATION TECHNOLOGY

High-Velocity Thermal Spray (HVTS), Integrated Global Services
HVTS is a robust solution that extends the life of existing equipment. HVTS cladding upgrades existing metallurgy to higher alloys and acts as a corrosion/erosion barrier in mission-critical equipment, including boilers, process vessels, towers and columns.

Largest coker unit reliability enhancement and expansion with uninterrupted operations, Reliance Industries Ltd.
This project involved replacing eight coke drums at Reliance's facility without shutting down coker operations, which would have been prohibitively expensive. This included the use of two of the world's largest coke drums that were used while the coke drums were replaced.

LUMINAI Refinery Advisor, Beyond Limits
Luminai Refinery Advisor is a cloud-based decision support tool that guides refinery operators to hit production planning targets and improves reliability in operations and startups.

BEST AUTOMATION TECHNOLOGY

Advanced process control system in LDPE, Reliance Industries Ltd.
For the first time, Reliance incorporated advanced process control in a 2,400-barg pressure tubular reactor in its low-density polyethylene (LDPE) plant. This supervisory control system monitors and regulates the existing distributed control system controllers for a safe and reliable operation.

ftServer, Stratus Technologies
ftServer is a fully integrated, continuously available hardware and software solution for running tier-one business critical workloads and edge applications. The 11th generation Stratus ftServer, released in 2021, incudes features to scale performance and provide maximum flexibility when deployed in edge environments.

PlantESP Plus, Control Station
PlantESP is a control loop performance monitoring (CLPM) technology that facilitates the identification and isolation of issues that undermine production efficiency and throughput. In August 2021, Control Station released PlantESP Plus, an enhanced version that equips users with advanced state-based analytics and addresses known limitations within other CLPM offerings.

Plantwide Optimizer, Honeywell
Devised as a novel type of primary advanced control (APC) controller, Plantwide Optimizer inherits a yield-property model from the planning layer and acquires operating constraints from the secondary APC layer, driving true sitewide optimization in a closed loop. This effectively addresses a long-existing gap between planning and control as the plan generated is often not the one implemented.

BEST CATALYST TECHNOLOGY

Fourtitude™ FCC Catalyst, BASF
This new technology is an FCC catalyst designed to maximize butylenes from resid feedstocks.

Reliance Olefins Removal Catalytic Technology (REL-ORCAT), Reliance Industries Ltd.
REL-ORCAT is a zeolite-based adsorbent for bromine index reduction in aromatics. It is regenerable, less costly and has a better lifecycle.

Layered organic hybrid-zeolite catalyst for alkylation of benzene with propylene, Sinopec

Sinopec has developed a layered MWW zeolite catalyst to enhance the alkylation of benzene with propylene.

BEST DIGITALIZATION TECHNOLOGY

AVEVA Data Hub, AVEVA

AVEVA Data Hub is a cloud-native operations data platform that removes the barriers to data sharing using the scale and flexibility of the cloud. It is fully integrated with AVEVA PI Server and with AVEVA's edge data solutions to form a comprehensive, edge-to-cloud data management platform.

Connect'In®, Axens

This technology includes a remote unit monitoring system displaying process data analyzed through high-fidelity kinetic models for engineers, operators and management on an online platform, as well as comparisons between the raw operating data and calculated operating parameters. Connect'In® utilizes immediate process data to deliver real-time, custom-made performance indicators using high-fidelity models.

Shiftconnector®, Eschbach

The Shiftconnector platform helps plant management record and report on shift team and production support activities. It uses an intuitive cloud-based software interface that allows for customization based on plant needs and individual role needs. It links shift teams and departments, providing a continuous 24/7, real-time status of plant operations.

Lummus Digital, Lummus Technology

Leveraging the latest developments in cloud computing, AI and data science, Lummus Digital helps customers eliminate the complexity and burden of analyzing the immense volume of data they create, simplifying their data streams to gain clearer insights to make better business decisions.

TrendMiner, TrendMiner, a software AG company

TrendMiner is an intuitive web-based, self-service analytics platform for rapid-fire visualization of time series-based process and asset data. Available as a SaaS, on-premises or private cloud solution, the plug-and-play software adds value immediately after deployment and enables cross-site teams to collaborate, learn and improve the overall performance of all production facilities.

BEST GAS PROCESSING/ LNG TECHNOLOGY

MeOH-To-Go® plant system, Modular Plant Solutions

The MeOH-To-Go® (or Methanol-To-Go®) modular plant reforms natural gas feedstock to syngas and then converts the syngas to Grade AA methanol.

DLNG liquified natural gas, Damietta Liquified Natural Gas

Fischer-Tropsch GTL, Uzbekistan GTL

In June 2022, Uzbekistan GTL began operations on the $3.4-B GTL plant. The facility processes 3.6 Bm^{3}y of natural gas from the nearby Shurtan Gas Chemical complex to produce GTL diesel, GTL kerosene, GTL naphtha and other fuels.

EXECUTIVE OF THE YEAR

Rajeev Kumar, Bharat Petroleum Corp. Ltd.

Gil Cohen, Imubit

BEST HEALTH, SAFETY OR ENVIRONMENTAL CONTRIBUTION

Honeywell Safety Watch, Honeywell

Honeywell Safety Watch is a real-time locating solution that monitors workforce safety. Its benefits include reducing mustering time, enabling faster search and rescue, improving security by monitoring restricted area movements, reducing unproductive time and delays, and improving contract workforce utilization and productivity.

VOCs reduction at Raffineria di Milazzo's SRUs complex stack, Raffineria di Milazzo, an Eni SpA and Kuwait Petroleum Italia JV

This project incorporated an innovative solution to mitigate volatile organic compounds at the emissions point of the Raffineria di Milazzo's refinery's sulfur recovery complex.

Digital enablement and remote monitoring deployment to ensure best-in-class HSEF performance for high-risk critical operation and shutdown, Reliance Industries Ltd.

The refiner's Jamnagar complex instituted new innovative practices to achieve a higher level of safety during startup/ shutdown of several units during COVID-19 lockdowns, which posed a serious threat to safety management systems due to a scarcity of skilled resources and personnel onsite.

BEST INSTRUMENT TECHNOLOGY

SERVOPRO DF-700 NanoTrace series, Gen 7, Servomex

The analyzer delivers proven, industry-leading trace and ultra-trace measurements of moisture in ultra-high-purity gases. The new Gen 7 improves field serviceability and features solid-state storage for ultimate reliability.

Proline 10 flowmeter line, Endress+Hauser

The latest edition Proline 10 flowmeter contains even more benefits for plant flow measurement than its previous iterations, including wireless remote access, errors and remedy information, low cost of ownership, minimal maintenance, and better diagnostics and monitoring functions, among other benefits.

BEST MODELING TECHNOLOGY

Aspen Fidelis™, Aspen Technology

This solution provides decision-makers with economics information that goes beyond the equipment level and accurately predicts future asset performance of the whole system. Aspen Fidelis provides detailed analysis to help guide strategic decisions for project prioritization such as spare parts management, tankage, demurrage reduction and debottlenecking efforts.

AVEVA™ Process Simulation, Sustainable Process Engineering, AVEVA

AVEVA Process Simulation brings agility to the entire process lifecycle of design, simulation, training and operations to deliver the process side of the digital twin and accelerate the engineering cycle. Engineers can collaborate across disciplines in a single integrated platform to explore all dimensions of a potential design and quantify the impact on sustainability, feasibility and profitability.

Visual MESA Supply Chain Scheduling (VM-SCS), KBC Advanced Technologies, a Yokogawa Company

VM-SCS delivers end-to-end analytics to support operations management of refinery and petrochemical complexes using an integrated supply chain model. It uses automated data integration to effectively deploy cutting-edge algorithms for scheduling optimization and best alternative search options.

Process Engineering ToolS Software (PETS® 5.0), Stratus Engineering, Inc.

PETS 5.0 is an engineering software product with more than 30 frequently used engineering modeling tools. The software performs hydraulic analysis, equipment sizing, relief calculations, instrument sizing, physical properties and much more.

HeX 360™, Symphony Industrial AI

The technology enables plant personnel to more effectively model and predict heat exchanger fouling.

Topnir™ Crude Modeling, Topnir

The technology provides a comprehensive crude assay in a matter of minutes and can obtain data on the following aspects of crude oil: API, sulfur content, total acid number, yields and many others.

UniSim® Design: Designing green hydrogen facilities, Honeywell

New improvements to UniSim Design allow for the modeling and design of green hydrogen facilities with added models for the two most prominent and established electrolyzer technologies: alkaline and proton exchange membrane electrolysis.

BEST PETROCHEMICAL TECHNOLOGY

Atol®, Axens

The Atol technology produces bio-ethylene from renewable resources with improved ethylene yield and lower energy consumption [including lower carbon dioxide (CO_2) emissions] with equipment optimization.

Eni innovative bio-based Friction Reducer Additive for lubricants, Eni

ENI has developed an innovative, bio-based and metal free friction reducer additive for next-generation lubricants derived from oleic acid and a glycerol derivative, both originated from renewable sources.

Novolen®, Lummus Technology

The latest Novolen technology brings unprecedented efficiency and cost effectiveness to a full range of polypropylene (PP) production. The process has also undergone a scaleup that has tripled its single line capacity, resulting in single reactor plant capacity exceeding 600,000 tpy.

Disentangled ultra-high molecular weight PE (UHMWPE), Reliance Industries Ltd.

Reliance has developed a catalytic technology for controlling entanglements of polymer chains at the polymerization stage, thus unshackling the polyolefin material and providing processability in the solid state for developing commercial products economically and in an eco-friendly manner.

R1–R2 reactors series operation for homo-polymer grades, Reliance Industries Ltd.

This two-stage reactor system is a novel PP gas phase fluidized bed reactor technology, which can increase production by more than 10%.

Thermal Crude-to-Chemicals (TC2C™), Saudi Aramco

TC2C's novel TC2C technology provides a high chemical yield which enables chemical production at world-scale ethylene capacity at low crude intake.

Catalytic Oxidative Dehydrogenation of Butenes (ODH Process), Sinopec

The ODH process produces butadiene from low-value C_4 olefins byproduct from methanol-to-olefins units, steam crackers and refineries. It is exothermic and can produce 1,3-butadiene with high selectivity at a lower temperature than steam cracking processes.

BEST REFINING TECHNOLOGY

Horizontal method for tray distillation and gas-liquid contact operations, ASIM Communication Pvt. Ltd.

This horizontal tray technology is an easy-to-install, less hazardous and efficient technology for distillation.

Dearomatized Kerosene (HP-DAK) technology, Hindustan Petroleum Corp. Ltd.

The HP-DAK technology is a combination of indigenous processes and catalysts to produce high-value specialty solvents from refinery streams.

Development, commercialization, scaleup and upgrade of a benzene recovery unit, Reliance Industries Ltd.

This technology is an optimized way to recover benzene from FCC gasoline streams.

Enhanced Annular Reforming Tube for Hydrogen and syngas (EARTH®), Technip Energies, Clariant Catalysts

EARTH is a drop-in insert consisting of a structured reforming catalyst and concentric flow tubes, installed in existing or new reformer tubes, to simultaneously achieve higher throughput and heat recovery in steam reformers.

SUSTAINABILITY

Algae-to-Oil (A2O), Reliance Industries Ltd.

The facility aims to develop the world's largest crude bio-oil technologies for renewable energy production by converting algae into biofuels.

AspenTech Sustainability Models, Aspen Technology

These 60 pre-calibrated sustainability models, validated

against research publications and customer data, streamline the creation of models to meet customer sustainability goals, helping to jumpstart or accelerate initiatives around energy efficiency, emissions management, the hydrogen economy, carbon capture and storage, and waste recycling.

Plastic FCC (PFCC) accelerated by virtual reactor simulation, Encina Development Group, LLC, CPFD Software
This technology is a PFCC process that converts mixed, hard-to-recycle plastics into chemicals such as light olefins and BTX aromatics.

Modular Carbon Capture and Storage (MCCS™), Entropy Inc.
This project was a collaboration between Entropy and Regina's Clean Energy and Technology Research Institute, which used the innovative MCCS technology and high-performance solvent: Entropy23™ (E23). E23 enables faster reaction kinetics and high CO_2 capture efficiency, among other benefits.

Honeywell Forge Energy and Emissions Management, Honeywell
This technology solution is based on Honeywell Forge APM that helps maintenance and HSSE teams go beyond predictive maintenance and focus on the energy efficiency of critical assets in the plant, enabling more sustainable operations.

Mina Al-Ahmadi refinery ATK pool sulfur specification initiative, Kuwait National Petroleum Company
This project ensured that the Mina Al-Ahmadi refinery's ATK pool adhered to the revised sulfur specification of 1%.

Blue ammonia demonstration project, Saudi Aramco
The objective of this project was to showcase Aramco's capabilities in producing and exporting CO_2-free blue ammonia as an alternative fuel.

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Air-cooled heat exchanger under natural convection

Determining whether or not to operate an air-cooled heat exchanger (ACHE) under natural convection is a challenge due to the limited information available for simulations of an ACHE under operation without fans. However, to manage fan failure cases under emergency conditions—i.e., bringing the ACHEs onstream from standby condition to meet emergency cooling requirements with none of the fans operating—sometimes the use of the natural convection option becomes unavoidable. This article, with the help of case studies, will evaluate the pros and cons of both options (operating an ACHE with fans running on emergency power, and in natural convection without fans operating) to meet emergency duty conditions.

The simulation of ACHE performance under natural convection has the following limitations:

1. The non-availability of sufficient experimental data: Most of the available experimental data based on wind tunnel tests are applicable for large natural-draft cooling towers with high natural-draft velocity, which are not applicable for ACHEs in process industries with relatively smaller sized towers and lower natural-draft velocity.
2. The impact of structures, heat source, local wind velocity and ground effect: These factors affect the natural draft by impacting the velocity of air at the exit of the ACHE. Since the available thermal design software does not fully consider these parameters in the sizing of the ACHE, a detailed computational fluid dynamic (CFD) analysis, with an associated impact in project cost and time, is required to properly simulate the impact of natural convection.
3. The effect of a chimney (stack) on performance: Although it has been established that the use of a chimney (stack) on top of an air cooler bundle (for a forced-draft unit) and on top of a fan ring (for an induced-draft unit) enhances the effectiveness of heat transfer due to natural convection, determining the exact relationship of chimney height with natural-draft performance is still a work in progress.

TABLE 1. Services with fans in operation

Service No.	Operation case	Fans in operation	Cooling mechanism	Remarks
1	Normal operation	All	Forced draft	Controlling case: fans on normal power
1	Emergency cooling	1 out of 4	Forced draft	Alternate case: fan on emergency power
1	Emergency blowdown	1 out of 4	Forced draft	Alternate case: fan on emergency power
2	Normal operation	All	Forced draft	Controlling case: fans on normal power
2	Emergency cooling	2 out of 3	Forced draft	Alternate case: fans on emergency power
3	Normal operation	All	Forced draft	Controlling case: fans on normal power
3	Emergency cooling	1 out of 6	Forced draft	Alternate case: fan on emergency power

INITIAL PROPOSITION: AVOID NATURAL CONVECTION AND USE EMERGENCY POWER

In view of these highlighted challenges in simulating ACHE performance under natural convection, it was proposed for the three services in TABLE 1 to operate the ACHEs during emergency conditions with the fans running on emergency power. TABLE 2 demonstrates that this option also reduced the capital cost by reducing the number of bays and/or heat transfer surface area compared to the natural-draft option—this is due to the higher airside velocity, resulting in higher mean temperature difference (MTD) and higher airside heat transfer coefficient.

How dependable is emergency power? The likelihood of failure of the fan motors to start for the emergency cooling scenarios, even with backup emergency power, under the following four conditions were reviewed:

1. Will the emergency cooling scenario with all fans off be the governing case?
2. If the above is true, can emergency cooling be met with the help of emergency power—which is being provided as backup power for the process unit—to power the fan motors during startup?
3. Will there be a case of "double

jeopardy" when the motors may fail to start, even with emergency power?

4. If double jeopardy is indeed a possibility, can the air cooler meet the specified duty by operating under natural convection?

A closer review of these conditions and past experience with similar applications have revealed that double jeopardy is indeed a possibility. This not only makes the use of emergency power for operating ACHEs under emergency cooling scenarios unacceptable, but will also result in the emergency cooling case (under natural-draft rather than forced-draft with one of the four fans on) becoming the control case. So, the emergency cooling case will govern the overall size of the ACHE, rather than normal operation.

Options—Natural draft with or without a chimney. To size the ACHE for the controlling case (i.e., the emergency cooling scenario), the following two options were reviewed to arrive at the final configuration of the ACHE. The simulation was carried out using a proprietary software[a].

Option 1: Natural convection without a chimney. The heat transfer area can be increased to manage the loss in overall heat transfer effectiveness due to natural convection by increasing the number of bundles/bay and the number of bays over and above those required for the normal operation case. To increase the stack effect and facilitate natural draft, increase the number of tube rows, over and above those required for the normal operation case.

Option 2: Natural convection with a chimney. Increase the velocity of natural convection over the ACHE bundles by providing a chimney (stack) on top of the bundle without increasing the number of bundles and bays from those required to cater to the normal operation case.

The results of the above two options, as well as the initial option, are summarized in **TABLE 2.** Since Option 2 requires less plot space for all three services and a much lower surface area, Option 2 was preferred over Option 1.

Type of draft: Forced or induced. The chimney can be provided either on the top of the tube bundles when fans (which are required for normal operation) are below the bundle (forced-draft), or on top of the fan ring when fans are above the bundle (induced-draft), as shown in **FIG. 1.**

The induced-draft option (with the chimney on top of the fan rings) has the

FIG. 1. An induced-draft ACHE with chimney. Courtesy of Spiro-gills.

TABLE 2. Evaluation of various options

Service No.	Option	Controlling case	Type of draft	Bare area, m²	Number of bays	Number of bundles per bay of bundle	Number of tube rows	Tube length, m	Number of fans per bay/ total fans	Plot area, m × m	Chimney height, mm
1	Initial	Normal operation (Note 1)	Forced	591	2	2	5	11	2 of 4 (Note 1)	11 x 10	Not applicable
1	1	Emergency cooling (Note 2)	Natural	4,968	9	2	8	11	-	54 x 10	No chimney
1	2	Normal Operation (Note 2)	Natural	555	2	2	4	11	-	12 x 10	4,000
2	Initial	Normal operation (Note 3)	Forced	176	1	1	4	11	3 of 3 (Note 3)	3.6 x 11	Not applicable
2	1	Emergency cooling	Natural	5,433	10	1	12	11	-	39 x 11	No chimney
2	2	Emergency cooling	Natural	184	1	2	2	11	-	7.8 x 11	7,000
3	Initial	Normal operation (Note 4)	Forced	851	3	2	6	11	2 of 6 (Note 4)	12.5 x 11	Not applicable
3	1	Emergency cooling (Note 5)	Natural	2,726	6	2	9	11	-	27 x 11	No chimney
3	2	Normal operation (Note 5)	Natural	912	3	2	6	11		14 x 11	3,000

Note 1: For the emergency cooling case, only one out of four fans will be in operation and the fan motor will be on emergency power.
Note 2: Emergency cooling, with all fans off and without a chimney, is the controlling case. However, with all fans off and with a 4-m chimney, normal operation is the controlling case.
Note 3: For the emergency cooling case, only two out of three fans will be in operation and the fan motor will be on emergency power.
Note 4: For the emergency cooling case, only one out of six fans will be in operation and the fan motor will be on emergency power.
Note 5: Emergency cooling, with all fans off and without a chimney, is the controlling case. However, with a 3-m chimney, normal operation is the controlling case.

following advantages over the forced-draft option:

1. Lower chimney height: The induced-draft configuration takes advantage of the chimney effect, resulting in a lower chimney height.
2. Lower impact of prevailing winds on ACHE performance: There is a relatively higher exit velocity in an induced-draft configuration due to the lower cross-sectional area of the fan ring, as compared to the bundle face area (which is almost 2.5 times that of the fan area) in the case of a forced-draft ACHE.
3. Better protection for the tube bundles: An induced-draft design protects the tube bundles from heavy rain with a plenum chamber on top of the tube bundle. So, a removable roof on top of the tube bundles to protect them from heavy rain during monsoon can be avoided with an induced-draft design.

Therefore, Option 2 with an induced-draft configuration was recommended for all three services.

Takeaway. Natural convection in combination with a forced- or induced-draft configuration, rather than running on emergency power, should be adopted for applications where the ACHE must be put into operation quickly from standby mode due to process considerations. The following points must be reviewed in detail before finalizing the ACHE configuration:

1. Considering the limited availability of performance data of an ACHE under natural convection in process industry applications, the various pros and cons of the natural-draft option with respect to other forms of operation (e.g., operating the ACHE fan motors under emergency power mode) must be reviewed during the project definition phase before finalizing the optimum mode of operation.
2. The type of draft (whether forced or induced) to be adopted in combination with natural convection mode should be determined based on site conditions (e.g., prevailing wind direction, presence of heat sources in the vicinity, annual rainfall) and customer requirements.
3. The limitations of the available software for ACHE performance simulation must be considered before deciding whether a detailed computational fluid dynamics (CFD) analysis will be required to simulate the performance of the ACHE under natural-draft conditions. HP

NOTE

[a] Heat Transfer Research Institute's (HTRI's) X_{ace} software, Version 7.3.2.

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Development of novel epoxy closed-cell foam for personnel and corrosion protection—Part 1

Most industrial assets operating at elevated temperatures require thermal insulation for energy conservation, thermal protection or process stabilization. As soon as the insulation is installed and in service, the risk of the underlying substrate of suffering from corrosion under insulation (CUI) increases. It should be noted that CUI represents a severe threat to the onstream reliability of many of today's refining, chemical, power generation, and pulp and paper industries, including onshore and offshore installations. The mechanism of CUI is initiated by the ingress of water into the thermal insulation, which traps the solution at the annular space between the metal substrate and the insulation. As a result, the substrate starts corroding under the insulation. Elevated temperatures exacerbate this corrosion mechanism.

NACE SP0198 defines carbon steel, austenitic and duplex stainless steels as the primary metallic substrates potentially suffering from CUI. In practice, CUI commonly appears in thermal ranges between 50°F and 350°F, or where there is cyclic operation of the equipment. For carbon steels, CUI manifests in the form of uniform and localized corrosion. For austenitic and duplex stainless steels, CUI is normally localized, leading to stress corrosion cracking if appropriate environmental conditions and stress levels are met.[1]

Additionally, thermal insulation can prevent operators and personnel in general from experiencing skin burns after accidentally touching substrates at moderately elevated temperatures. As technology has expanded, the processes and associated equipment and pipework have become more complex and convoluted, creating more situations where workers are exposed during their shifts. Subsequently, worker organizations and governmental agencies have demanded the increased use of insulation for personnel protection, mostly for metallic equipment at ≥ 140°F. No mandates or statutes govern the upper limit temperature for personnel protection.

To correct potential CUI problems and provide effective thermal insulation, asset owners are urged to implement comprehensive corrosion and insulation protection strategies. As a rule, any such strategies should comprise at least three components: coating, insulation and jacketing. High-quality corrosion resistance coating is applied to the substrate and, if it is properly applied, should perform as a water barrier isolating the substrate from the trapped water. Conversely, the insulating material should be protected with an effective and durable weather barrier or jacketing.

However, today's high energy prices—and, at times, maintenance budget reductions—render these solutions costly and laborious. This is the reason why asset owners and process engineers are con-

TABLE 1. Foaming perspectives

Perspective	Types	Comments
Material	Thermoplastic/Thermoset	A wide variety of thermoplastics, such as polypropylene, polyethylene, polystyrene, polycarbonate and polyvinyl chloride, have been used in foam processing techniques. Epoxy is an example of a thermosetting insulating material.
Mechanism	Physical/Chemical	Physical (or soluble) mechanism involves physical action (e.g., blowing a gas into a polymeric matrix). Chemical action is when the foaming mechanism solely depends on a chemical reaction (e.g., the reaction of an isocyanate with water).
Nature	Flexible/Rigid	Flexible foams tend to be less cross-linked than rigid foams.
Structure	Closed-cell/Open-cell	Closed-cell refers to a foam that minimizes permeability by entirely isolating the substrate, whereas open cells are higher in permeability.
Cell Size	Microcellular/Cellular	Microcellular cell sizes are reported in the order of 10 μm.[4]
Density	High-density/Low-density	The density of foams varies, in general. Lower densities are achieved when the polymer holds higher proportions of air.

stantly looking for ways to reduce labor or implementation costs by using other non-conventional, cost-efficient alternatives. One of these alternatives, which seems to be of growing interest, is the use of thermal insulating coating systems that can also provide corrosion resistance.

This article details the development of a novel epoxy closed-cell foam insulating and corrosion protection barrier by a coating manufacturer. Design considerations of such a material, fitness-for-service testing and results will be presented, as well. Potential application areas and benefits, including worksite personnel and CUI protection, will also be discussed.

Background. Polymer foaming, simply defined, is the technology that allows the generation and stabilization of bubbles within a polymeric matrix.[2] When a system is excited into an unstable foaming state, a stabilization mechanism must be established in time to transform the foaming into a stable foamed product. In theory, it sounds very simple to accomplish; in reality, it is not. Produced foams can be categorized in accordance with different perspectives,[2] as detailed in **TABLE 1.**

Epoxy foams are becoming a more attractive alternative to the more prevalent urethane foams used as thermal insulators. Reasons for this include the mechanical strength of epoxy matrices and the elimination of toxic or sensitizing isocyanates, typically used in the polyurethane formulations.[3] Additionally, some literature has cited the rigidity and dielectric properties (volume resistivity, dielectric constant and dissipation factor) of epoxies over polyurethanes. Whether epoxies or polyurethanes, polymeric foaming requires the presence of a blowing agent, herein defined as a substance that produces a cellular structure in a polymer mass by releasing a gaseous phase due to thermal decomposition or a chemical reaction.[4]

The blowing agent plays a significant role in both the manufacture and performance of the polymeric foam. In the case of foaming of high molecular weight polymers [e.g., polystyrene (PS), polyolefins, polyamides, polyester], the blowing agent modifies the rheology of the polymer during foam formation and shaping. In cases where polymerization, foaming and shaping all happen in one step, [e.g., during the formation of typical polyurethane (PU), epoxy or phenolic foams], the blowing agent not only affects the liquid viscosity and thermal his-

TABLE 2. Proprietary epoxy foam[a] design considerations

Technical	Excellent corrosion protection	A system that would show no signs of failure or damage after exposure to simulated corrosion under insulation scenarios, salt spray and water immersion.
	Cool-to-touch properties	A system that could offer safe touch by reducing the surface temperature of the industrial equipment to less than 140°F, allowing direct hand contact.
	Excellent thermal insulation	A system with reduced heat transfer across its volume.
	No primer or topcoat required	A system with adequate adhesion to mechanically prepared and clean substrates without any conditioning, and robust enough to provide corrosion protection by itself.
	Solvent-free	Solvent-free epoxy systems show greater mechanical properties when compared to solvented formulations. Experimental work has shown that solvent remaining within the epoxy can hinder the cross-linking process, resulting in lower exotherm, initial curing rate, reaction order and glass transition temperatures.[6]
	Durability/aging	A foaming system that would show no cracking or sign of deterioration when subjected to thermal cycling.
Practical	Tolerance to minimal surface preparation	A foam that could be applied onto substrates cleaned to the requirements of both SSPC-SP 10[7] and SSPC-SP 11[8] and profiled to at least 1 mil and successfully offers corrosion protection.
	Ease of application	A system that could be conveniently applied by brush, cartridge spray or heated plural component airless spray.
	Short overcoat times	A system that could be overcoated with additional coats, if needed, as soon as possible.
	Fewer layers (coats) required	A foaming system that would need fewer layers (coats) than most typical coating systems to achieve insulative properties through a controlled catalytic process.
	Quick return to service	A foaming system with shorter drying times to provide a definite appeal for asset owners.

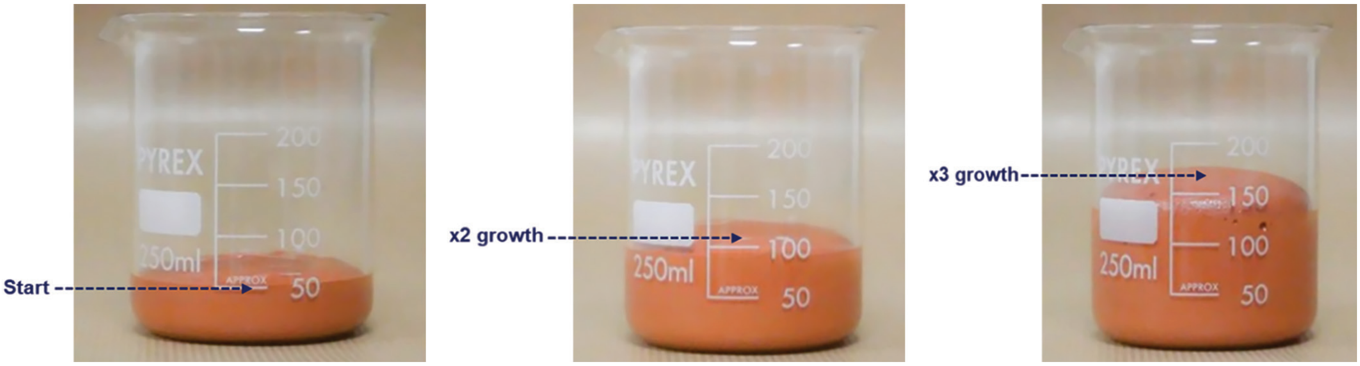

FIG. 1. The proprietary epoxy foam[a] as applied inside a beaker and allowed to cure until achieving growth of up to three times its original thickness.

tory, but also the compatibility, reactivity and phase mixing of the components.[5]

Some of the most used physical blowing agents include halogenated hydrocarbons, hydrocarbons and inert gases, among others, which can be bubbled through thermoplastic materials or expanded by heat treatment. One of the most common blowing agents is water, which can be reacted with isocyanates to form an unstable intermediate of carbamic acid that readily decomposes to generate carbon dioxide (CO_2).[4] Alternately, alkylhydrosiloxanes can be used to produce epoxy-based foams. These reactions are well-documented.

As previously discussed, years ago, epoxy resins were not as readily foamed as urethanes; therefore, they saw limited use in encapsulant applications. This is changing because of the potential advantages of epoxy foams over urethane foams. The primary advantage is the elimination of toxic or sensitizing isocyanates used in polyurethanes, which is being enforced by health and safety legislations. Polyurethanes are readily foamed by the simple addition of water. Epoxies, on the other hand, do not foam in the same way.

Designing an epoxy foam. This section details the development of a novel epoxy closed-cell foam insulating and corrosion protection barrier by a coating manufacturer. This barrier, referred to here as a proprietary epoxy foam[a], uses a solvent-free phenol formaldehyde Novolac epoxy as a base and a polyamine as a solidifier. Both components react in stoichiometric amounts to yield a thermosetting polymer, as in a well-documented mechanism of nucleophilic addition to an epoxy. Specifics of the epoxy resin and amine curatives used are proprietary and, therefore, not detailed and included in this article. During this polymerization process, a modified polysiloxane is used as the blowing agent. Its chemistry and reaction mechanism constitute proprietary details and, again, are not discussed here. Both the chemistry and quantity of the blowing agent are used to adjust the foaming action and final density of the epoxy foam[a]. The polymeric system is further modified with functional extenders to achieve specific qualities depending on target design considerations.

TABLE 3.

Thermal conductivity	BS EN 12667[9]/ ASME C177[10]
Corrosion under insulation (CUI)	Modified ISO 19277[11] section 7.4
Salt spray	ASTM B117[12]
Cool-to-touch	ASTM C1055[13]
Thermal cycling	ISO 19277 section 7.3
Pull-off adhesion	ASTM D4541[14]
Degree of blistering evaluation	ISO 4628-2[15]
Degree of rusting evaluation	ISO 4628-3
Degree of cracking evaluation	ISO 4628-4

Upon polymerization, the epoxy foam resulted in a cured epoxy foam with the following characteristics: rigid closed cell, low density/light weight, and a final expansion of up to three times its applied thickness. **FIG. 1** shows the growth of the foam during curing. **FIGS. 2** and **3** illustrate an application of the proprietary epoxy foam[a] onto a pipe section and a cross-section cut, respectively.

Design considerations for the epoxy foam were based on both technical target requirements and a practicality approach, as summarized in **TABLE 2.** The epoxy foam was subjected to the tests and evaluation protocols shown in **TABLE 3** to ensure that it met the design criteria previously discussed. Where possible, internationally recognized standards were used. HP

ACKNOWLEDGEMENT

This paper was presented by the author or assigned speakers at the Coatings+ 2021 conference.

NOTE

[a] BZ5871-EF epoxy foam

FIG. 2. Application of the proprietary epoxy foam[a] onto a pipe section for testing purposes.

FIG. 3. Cross-section of the proprietary epoxy foam[a] showing foam consistency

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Case studies: Evaluation of the soundness and remaining life of PSA vessels with weld defects

Multiple defects were found in pressure swing adsorption (PSA) vessels during an outage of one of four PSA process units. The option for immediate repair during the shutdown was infeasible due to time constraints, particularly without new catalysts for replacement. The concerns were whether the equipment was safe to start up again after the outage and how long the vessels could continue to be operated. A fitness for service (FFS) assessment and remaining life assessment were undertaken to assess the current status of the cracks (defects), and to assist in future outage plans and inspection based on the remaining life results.

A 3D finite element (FE) model of a PSA vessel was generated to determine the stress distribution of the critical areas where the defects were found, and a fracture mechanics analysis was carried out for the FFS assessment and remaining life assessment in accordance with API 579 and BS7910 standard procedures. This article describes the procedures of FFS and remaining life assessments and their results in detail in the following sections.

TABLE 1. Summary of the major geometry of the PSA vessel

Item	Values, mm
Cylinder internal diameter	3,300
Cylinder wall thickness	40
Elliptical heads 2:1 thickness	45
Distance between tangent lines (TL) of heads	6,030
Internal diameter of N2 top nozzle	483
Outer diameter of N2 top nozzle	633
Internal diameter of N1 bottom nozzle	318
Outer diameter of N1 bottom nozzle	488
Radius of internal diameter of nozzle to shell	25
Radius of outer diameter of nozzle to shell	50

FINITE ELEMENT STRESS ANALYSIS

FE models. A simplified FE model of a PSA vessel (including top and bottom nozzles) was generated, as shown in **FIG. 1,** and a summary of vessel geometry is presented in **TABLE 1.** The model consisted of 37,164 quadratic brick elements with a global mesh seed size of 50 mm, a minimum of 16 elements around a circle, and three elements through the wall thickness.

This model was then treated as a generic model that was used for other vessels; therefore, the geometry, boundary conditions and loads remained the same.

Boundary condition and loading condition. A kinematic constraint was applied to the location of the vessel where the connection to the skirt would be. Constrained to an arbitrary reference point but free in the radial direction, the reference point (in turn) had all degrees of freedom constrained. Kinematic constraints were additionally applied to the top and bottom nozzles modeled. Both were constrained to individual reference points, centered flush with the end

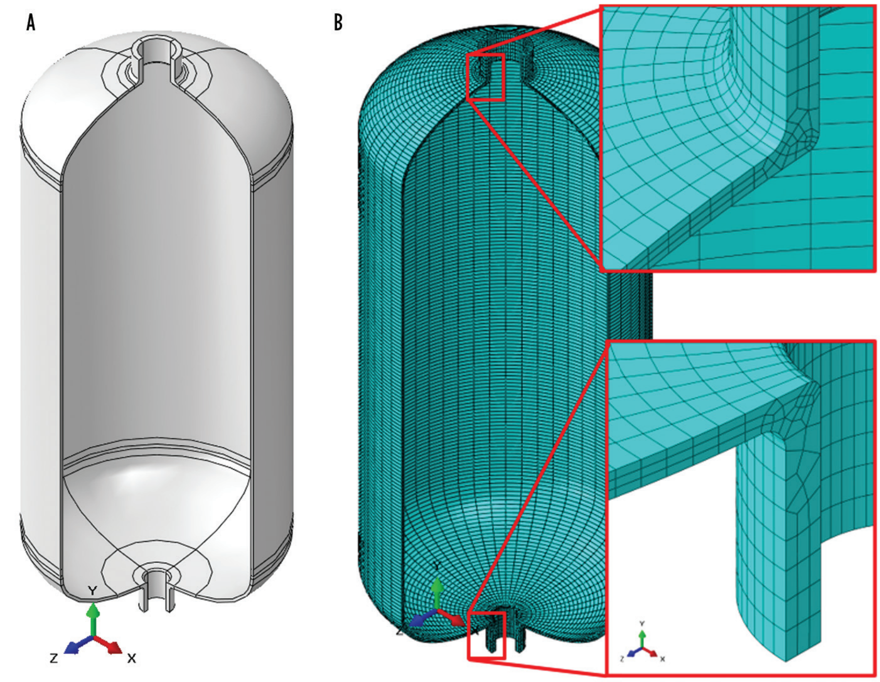

FIG. 1. FE model of a PSA vessel (A) geometry and (B) FE mesh.

face of the nozzle but free in the radial direction. This allowed for the correct representation of the nozzle end loads (as system loads and bending moments could be applied as required) as well as constraints due to the continuous connection to pipework.

The loads considered for this assessment were self-weight due to gravity, internal pressure, and loading resulting from internal pressure, such as nozzle end loads (blow-off loads). No additional system loading was available, and thermal loading or thermal transients were not considered, which is likely insignificant, considering operating temperature.

TABLES 2 and **3** summarize the loading cases and the actual loads (e.g., pressure and axial stress) applied on the model. The basic material properties of ASTM A516Gr.70 for FEA were the same for all 12 vessels:

- Density of 7,850kg/m^3
- Young's modulus of 207 GPa
- Poisson's ration of 0.3.

FEA result. Linear elastic stress analyses were performed based on a finite element model of PSA vessels so the stresses in the critical locations of interest where cracking was detected could be resolved cor-

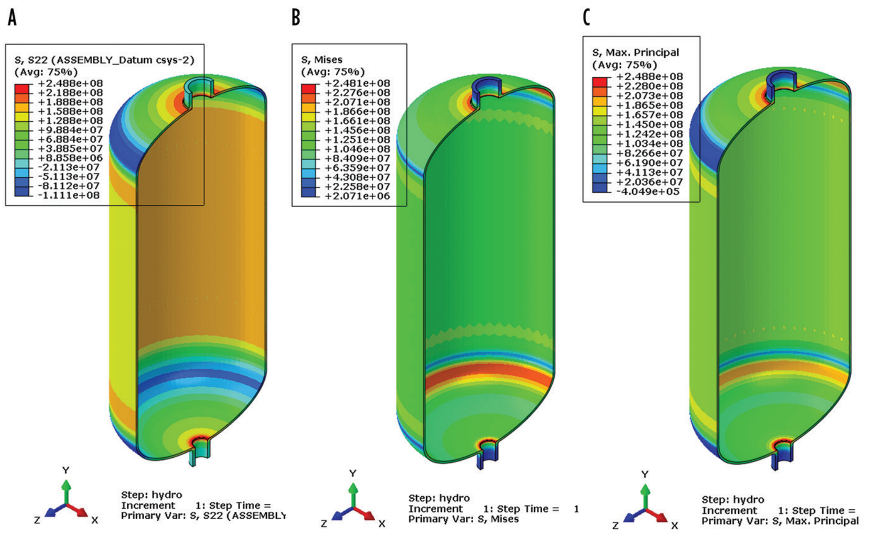

FIG. 2. Resulting stresses through a section of the vessel due to the hydrotest load case: (A) hoop stress, (B) von Mises stress and (c) maximum principal stress.

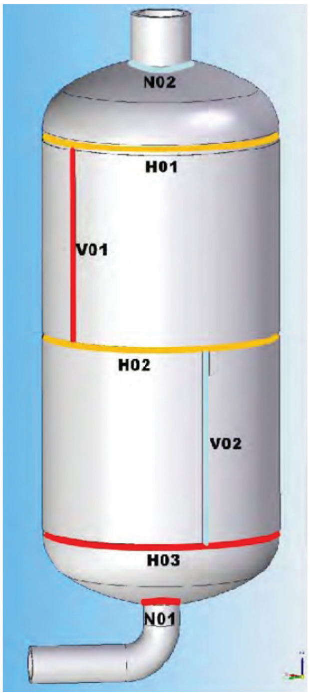

FIG. 3. Weld ID used in the inspection and FFS assessment.

TABLE 2. Load cases considered for assessment

Load case	Condition	Objective
1	Hydrotest	Critical flaw size determination
2	Maximum operating	Maximum stress for fatigue crack growth calculations
3	Minimum operating	Minimum stress for fatigue crack growth calculations

TABLE 3. Summary of loads applied for assessment

Load case	Internal pressure, Mpa	Axial force top nozzle, kN	Axial force bottom nozzle, kN
1	3.82	700.76	303.76
2	2.01	368.35	159.67
3	0.03	5.39	2.34

TABLE 4. Summary of stress results

	Load cases					
	Hydrotest		Maximum operating		Minimum operating	
Location	Membrane stress, Mpa	Bending stress*, Mpa	Membrane stress, Mpa	Bending stress*, Mpa	Membrane stress, Mpa	Bending stress*, Mpa
Top nozzle, N02	181.6	29.7	95.3	15.6	1.1	0.08
Bottom nozzle, N01	172.7	22.8	90.9	12.1	1.6	0.4
Top head weld, H01	78.3	2	41.1	1.1	0.5	0.04
Middle body weld, H02	158.2	–2	83.2	–1	1.2	–0.02
Bottom head weld, H03	77.8	1.9	40.7	1	0.1	0.01
Upper vertical weld, V01	115.6	20.1	60.8	10.5	0.94	0.13
Lower vertical weld, V02	115.5	20.1	60.7	10.6	0.8	0.2

* Bending stress at external surface

rectly and accurately. However, the model was not designed to assess structural integrity of the entire vessel, such as inside the vessel, skirt, vessel support, etc.

Views of a cross-section of the PSA vessel model for the hydrotest load case, hoop stress, von Mises stress and maximum principal stress are shown in **FIG. 2.**

The locations for the extraction of the stresses for the FFS assessment of the vessel for weld locations are N02 (top nozzle), N01 (bottom nozzle), H01 (top head weld), H02 (middle body weld), H03 (bottom head weld), V01 (upper vertical weld) and V02 (lower vertical weld), as illustrated in **FIG. 3.**

The through-thickness stress distributions of the welds selected for the assessment are shown in **FIG. 4.** The stress component was chosen depending on the crack orientation with respect to the weld location (e.g., a hoop stress component for transverse cracks in circumferential welds and an axial stress component for transverse cracks in seam or vertical welds). These results have been summarized in **TABLE 4** in terms of membrane and bending stresses, which are required for the fracture mechanics assessments.

FFS assessment. The FFS assessment and remaining life assessment for the crack-like defects found in the welds were carried out in accordance with guidance given in API579 and BS7910. The assessment included two major components:

- Determining the criticality of the defects using a failure assessment diagram (FAD)
- Calculating the remaining life of the most critical defect from each vessel.

Flaw geometry, location and orientation. The most critical defects were selected from the inspection reports based on the defects' height and the ligament. The assumptions made for the FAD assessment were:

- The lengths of defects were the same as the weld size (as shown in **TABLE 5**), i.e., wall thickness as the flaw lengths were not available.
- The defects are located at the highest stress area within the weld.
- Subsurface or embedded defects are characterized as elliptical cracks, and surface defects are characterized as semi-elliptical cracks.

The generic geometry of the elliptical embedded flaw and semi-elliptical surface flaw used in the FAD assessment are presented in **FIG. 5.**

In this assessment, the lengths (2c as indicated in **FIG. 5**) were considered having the same size as the weld size, and the crack depths (labeled 2a as an embedded crack, labeled "a" as a surface crack) were taken from the inspection report. Flaw locations and orientations were as specified by the inspection report. The flaw orientation was assumed normal to the weld.

Primary and secondary stresses. The primary stresses used for this assessment come from the "hydrotest" loading condition shown in **TABLE 4** of the FEA results.

The PSA vessels were subjected to post-weld heat treatment (PWHT); therefore, secondary weld residual stresses in accordance with BS7910 for PWHT conditions have been applied. For flaws that are aligned parallel to the weld, the residual stress can be assumed as 30% of the yield strength of the parent material at room temperature. For flaws that are aligned transverse to the weld, the residual stress can be assumed as 20% of the lesser of the yield strength of the parent and weld materials at room temperature.

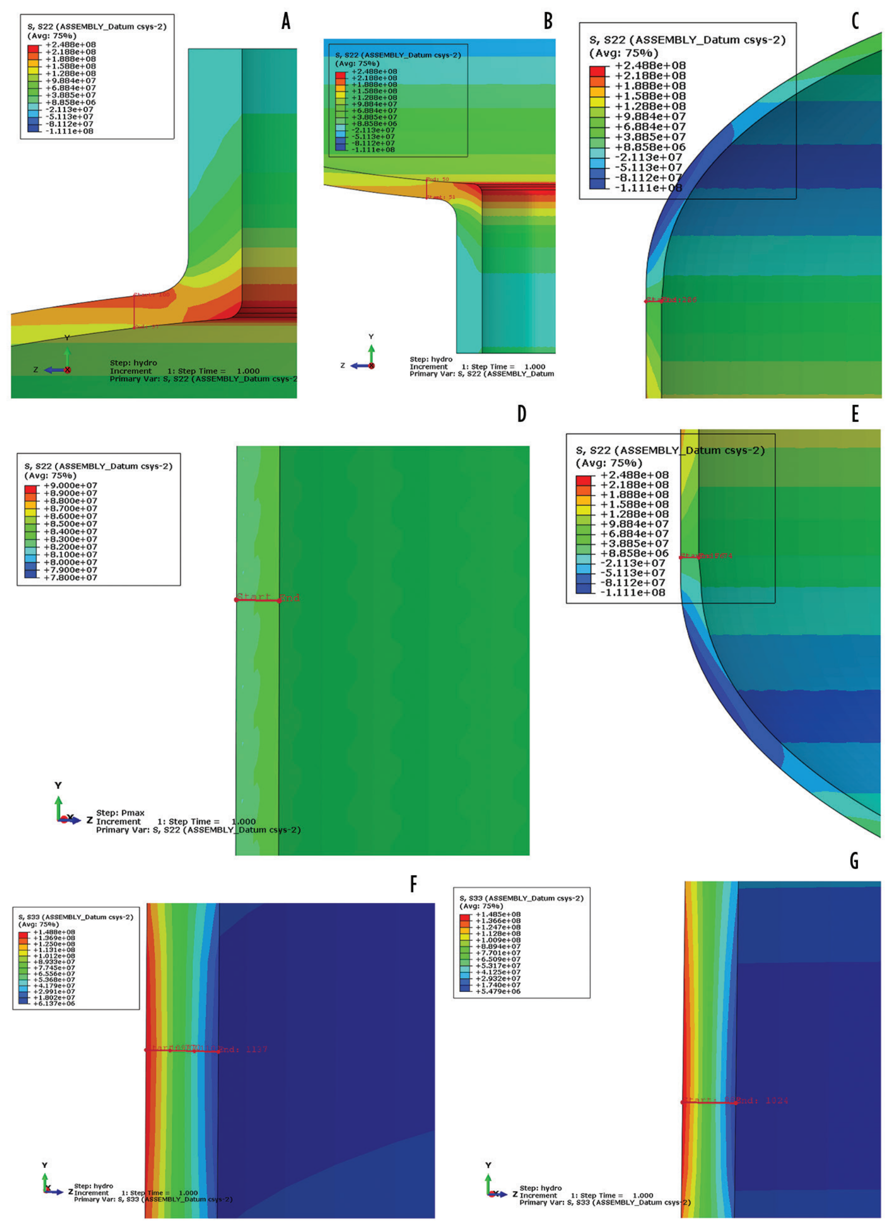

FIG. 4. Through-wall stress extraction path for cracking at the weld location: (A) top nozzle, N02; (B) bottom nozzle, N01; (C) top head weld, H01; (D) middle body weld, H02; (E) bottom head weld, H03; (F) upper vertical weld, V01; and (G) lower vertical weld, V02.

Material properties. The tensile properties and fracture toughness for the vessel material (SA516 Gr. 70) used for the FFS assessment are summarized in **TABLE 6.**

FAD assessment results. The cracks found in each vessel have been assessed using an FAD. Selected FADs are shown in **FIGS. 6** and **7.** The assessment revealed:

- Most of the cracks assessed for vessels D01–D12 fell within the FAD envelope; therefore, they are acceptable for continued operation.
- The crack, D10-N02-2 (the crack in the top nozzle weld in the D10 vessel) was outside the FAD envelope, indicating the current crack size was unacceptable (**FIG. 7**).
- The crack D01-H02-2 (the crack in the middle body weld in the D1 vessel) was inside the FAD envelope, but with a very small margin, as shown in **FIG. 6.** This implies a potential risk of this crack being critical in the near future, even if its current crack size is acceptable.

Refined FAD assessment. The crack lengths used for the initial FAD assessments were determined based on a conservative assumption of equaling them to the weld size. The FAD assessments for the most critical cracks, D01-H02-2 (Vessel D01) and D10-N02-2 (Vessel D10) were refined by using the measured crack lengths, which were provided after the initial assessment.

The measured length for D01-H02-2 and D10-N02-2 were 16 mm and 12 mm, respectively; however, the a/c (height-to-length) ratio exceeded the valid range, therefore the closest valid ratio of 0.97 was applied. The refined assessment revealed that both cracks fell inside the FAD envelope (as seen in **FIG. 8**), indicating that both cracks were acceptable.

REMAINING LIFE ASSESSMENT

Damage mechanism and crack growth. The PSA vessels have been subjected to a cyclic loading frequency of 100 loading cycles per day. This cyclic loading operation was believed to be the major driving force of the crack growth, so a fatigue cracking mechanism was applied in the remaining life assessment. The remaining life is determined when the crack continues to grow until it reaches critical flaw size.

Multiple scenarios exist for how the crack could grow to reach critical flaw size:

- The initial flaw could grow from being an embedded flaw, to breaking the surface, then through the wall before reaching its final critical flaw size.
- The initial flaw could grow from being an embedded flaw, to through the wall to reach its final critical flaw size.
- The initial flaw could grow from being an embedded flaw, to breaking the surface, which could then represent its final critical flaw size.
- The initial flaw could grow from

TABLE 5. Summary of the remaining lives of all vessels

		Critical flaw size			Remaining life		
Vessel	Crack ID	Depth, mm	Length, mm	Flaw type	Cycles	Days	Yr
D01	D01-H02-2	36.12	36.17	Embedded	37,753	377	1
D02	D02-N01-1	32.6	51.4	Embedded	195,918	1,959	5.3
D03	D03-N02-2	29.7	74.4	Surface	171,266	1,712	4.6
D04	D04-H02-1	31.5	63.4	Surface	134,316	1,343	3.7
D05	D05-N01-2	28.9	72.3	Surface	191,203	1,912	5.3
D06	D06-N01-3	29.9	52.4	Surface	138,942	1,389	3.8
D07	D07-N02-1	28	49.8	Embedded	203,140	2,030	5.5
D08	D08-N01-3	31	72.3	Surface	124,678	1,246	3.4
D09	D09-H02-1	39.8	71.7	Surface	127,234	1,272	3.4
D10	D10-N02-2	34.2	34.6	Embedded	30,232	302	< 1
D11	D11-N02-1	24.2	55.4	Surface	124,029	1,240	3.4
D12	D12-N02-2	29	49.2	Embedded	87,478	874	2.3

TABLE 6. Material properties assumed in the FFS assessment

Location, weld ID	Temperature, °C	Yield stress[1], Mpa	UTS[1], Mpa	Fracture toughness, K_{mat} ($N/mm^{3/2}$)
N01, N02	20	260	485	3,225
N01, N02	95	260	485	3,276
N01, N02	121	260	485	3,276
H01, H02, H03, V01, V02	20	260	485	3,225
H01, H02, H03, V01, V02	95	260	485	3,276
H01, H02, H03, V01, V02	121	260	485	3,276

[1] Lower bound values have been assumed as per ASME Sec. II Part D

TABLE 7. The most critical flaws identified for each PSA vessel

Vessel	Defect ID	Crack type	Height, mm	Length, mm	Ligament, mm	Crack location close to
D01	D01-H02-2	Embedded	31.7	40	3.7	External surface
D02	D02-N01-1	Embedded	11.1	45	18.7	External surface
D03	D03-N02-2	Surface	10.4	45	-	External surface
D04	D04-H02-1	Embedded	18	40	5.2	External surface
D05	D05-N01-2	Embedded	7	45	8.8	External surface
D06	D06-N01-3	Embedded	11.4	45	9.6	External surface
D07	D07-N02-1	Embedded	8	45	17.6	External surface
D08	D08-N01-3	Embedded	15.3	45	2.8	External surface
D09	D09-H02-1	Embedded	22.3	40	6.3	External surface
D10	D10-N02-2	Embedded	30.2	45	7.4	External surface
D11	D11-N02-1	Embedded	8.2	45	8.3	External surface
D12	D12-N02-2	Embedded	12.4	45	11.7	External surface

being an embedded flaw to reach its final critical flaw size and still be embedded.

- The initial flaw could grow from being a surface flaw, to through the wall to then reach its final critical flaw size.

The assessments focus on the state of the vessel before leakage occurred; in other words, the crack may keep growing as an embedded or surface flaw before the depth penetrating the wall thickness of the vessel. Therefore, under current operating loads, the remaining life of a vessel was defined as the remaining time before the most critical flaw reached either its critical flaw size (i.e., outside of the safe area in the FAD) or prior to being developed as a through-wall thickness crack (i.e., before leakage occurs). The most critical defects from each vessel, as summarized in **TABLE 7,** were considered for the remaining life assessment of the vessels.

Cyclic stresses. Based on the maximum and minimum operating stresses shown in **TABLE 4** of the FEA results section, the cyclic stresses required for the fatigue crack growth assessment were calculated and are summarized in **TABLE 8.**

Fatigue crack growth model. The fatigue crack growth analysis was carried out using the Paris law (Eq. 1):

$$(da/dN) = C(\Delta K)^m \qquad (1)$$

where:

da/dN = fatigue crack growth rate, mm/cycle
ΔK = Stress intensity range, MPa $\sqrt{m}$
C, m = Paris law coefficient and exponent.

C and m are the material parameters available from API 579 and BS 7910, which are applicable to weld steel joints in air environment conditions up to 100°C. $C = 1.29 \times 10^{-12}$ and exponent, $m = 2.88$.

Results of remaining life assessment. **TABLE 5** summarizes the remaining life assessment results from 12 vessels (D01–D12) in terms of remaining operating cycles, days and years. The remaining life in days and years were calculated based on the operating condition of 100 cycles per day.

In general, most of the PSA vessels will last more than 3 yr before the initial cracks reach their critical flaw size,

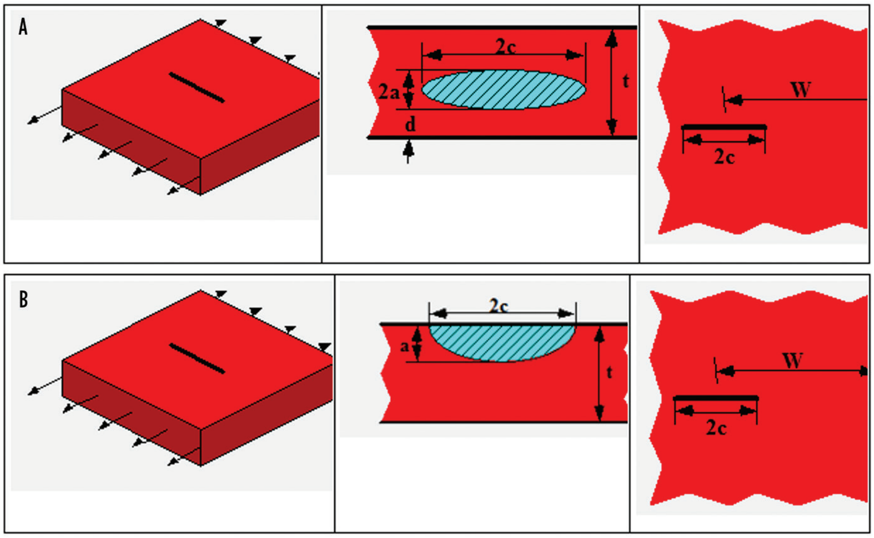

FIG. 5. Generic geometry of flaws: (A) an elliptical embedded flaw and (B) a semi-elliptical surface flaw.

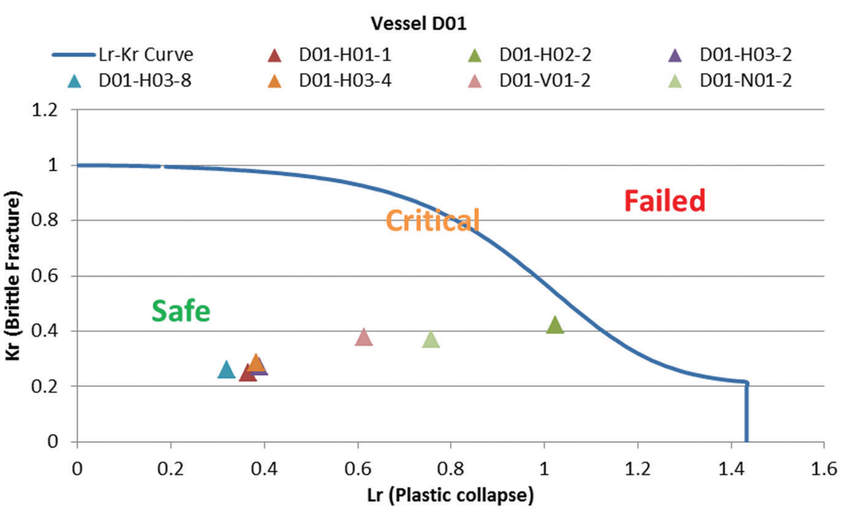

FIG. 6. An FAD of vessel D01.

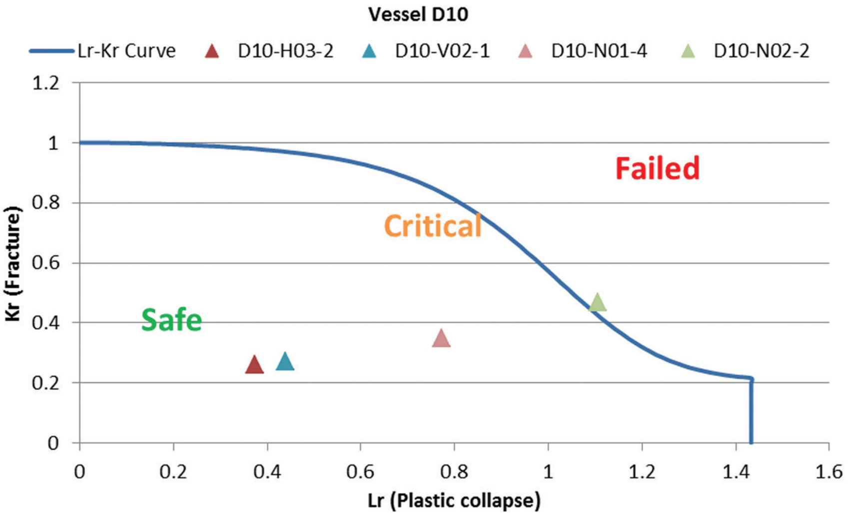

FIG. 7. An FAD of vessel D10.

whereas vessels D01, D10 and D12 have relatively shorter lives (i.e., 1 yr, < 1 yr and 2.3 yr, respectively).

The graph in FIG. 9 shows an example of how the current cracks grow by fatigue prior to becoming critical.

Takeaways and recommendations. The FFS assessment and remaining life assessment were carried out for the PSA vessels D01–D12, where defect indications were discovered in the welds during the inspection. The main objective of the assessments was to determine whether the vessels with the defects were fit for service and how long the vessels can be operated. The following conclusions and recommendations were made from the assessment:

- The selected critical cracks assessed for vessels D01–D12 fell within the FAD envelope; therefore, the cracks are acceptable for continuing operation.
- The cracks in vessels D01 and D10 were found be the most critical.
- The remaining life of each vessel was determined based on the assumption that the current crack continues to grow by fatigue as a result of cyclic loading until it reaches critical flaw size.
- The remaining life of most of the PSA vessels (i.e., D02, D03, D04, D05, D06, D07, D08, D09 and D11) ranges from 3 yr–5 yr.
- Vessels D01 and D12 have relatively shorter lives: 1 yr and 2.3 yr, respectively. Vessel D10 has the shortest life: 302 d.
- It is recommended to prioritize vessels D10 and D01 for repair, particularly the top nozzle weld (N02 weld) in vessel D10 and the middle body weld (H02 weld) in vessel D01.
- If normal operating conditions change (especially the frequency of cyclic loading and maximum pressure), or there is a departure from the operating conditions assumed in this assessment that could be detrimental, it is recommended to carry out repeated assessments under these revised operating conditions to ensure the vessel remains fit for service. HT

TABLE 8. Cyclic stresses used for remaining life calculations

	Cyclic stress = Max op. – min op.		
Location	Membrane stress, Mpa	Bending stress, MPa, internal	Bending stress, MPa, external
Top nozzle, N02	94.2	15.5	–15
Bottom nozzle, N01	89.3	11.7	–9.9
Top head weld, H01	40.6	1	–1
Middle body weld, H02	82	–1.08	1.08
Bottom head weld, H03	40.6	1	–1
Upper vertical weld, V01	59.9	10.4	–10.4
Lower vertical weld, V02	59.9	10.4	–10.4

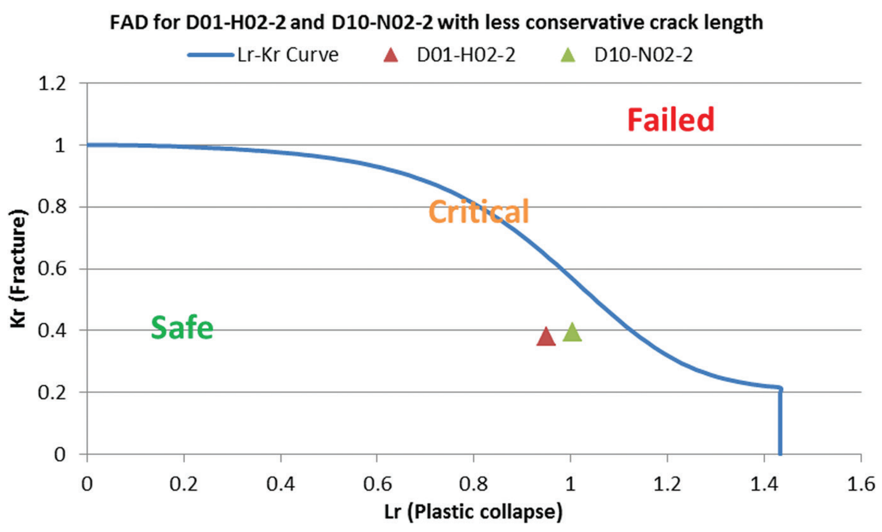

FIG. 8. A refined FAD of the D01-H02-2 defect and the D10-N02-2 defect.

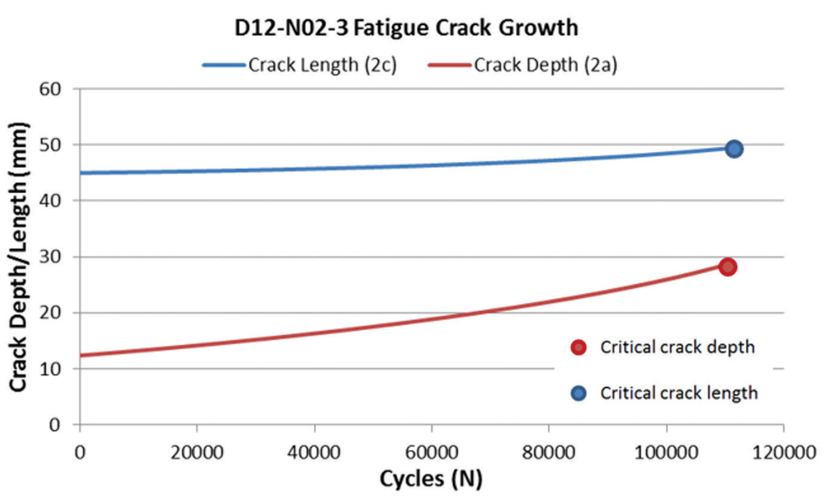

FIG. 9. Fatigue crack growth of the initial crack size to the limiting flaw size for D12-N02-3.

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Data, algorithms and collaboration combine for machine-learning success

Process manufacturers are investing significant resources in machine-learning (ML) to increase reliability, profitability and sustainability in their operations—saving millions of dollars in short periods of time through increased efficiency. As interest in ML grows, focus is rightfully placed on developing and enhancing the associated algorithms, but manufacturers must examine the results of these algorithms to ensure that ML efforts are successful. This is because operationalization of algorithms, not an algorithm itself, is the linchpin to providing meaningful value.

Successfully applying ML in an industrial setting requires participation from engineers and other plant operations personnel who collectively contribute knowledge of process manufacturing procedures and associated sensor data. Close collaboration between process and equipment subject matter experts (SMEs), who must be able to trust the predictions that a model creates, is critical to the success and longevity of an ML implementation. With the right advanced analytics applications and active SME involvement, process manufacturers can avoid potential frustrations and derive sustained value from ML initiatives.

SMEs, data and ML are interdependent. Across the process industries (including oil, gas and chemicals), reactive maintenance programs are common, forcing plant personnel to make operational adjustments only after identifying inefficiencies in a report or, worse, after equipment fails. Reactive maintenance can lead to excessive maintenance costs and can also cause damaging incidents.

By instead implementing applications to proactively detect and predict issues—such as process variances, quality deviations and compliance violations—before they happen or as they begin to develop, plant personnel can lower maintenance costs, increase uptime, and spend more time optimizing processes and experiencing fewer troubleshooting failures.

Transitioning from reactive to proactive maintenance requires synthesis of data from a variety of sources, along with the ability to apply analytics across multiple process units within a plant. To ease this transition, engineers and process experts gravitate toward no-code ML solutions with accessible and intuitive interfaces that plug into existing workflows to solve domain-specific problems.

Advanced analytics applications drive ML success. Advanced analytics applications empower plant personnel to view and analyze time series data from multiple sources to gain an overall operational view of their units and facilities. These applications connect to various data sources (including process historians, lab and sampling databases, maintenance systems, and others), thus providing teams with a clear view of information through a single interface, without replicating data or compromising original repositories. Process experts can use these applications to access, cleanse and contextualize data, which are critical steps for successful ML implementations.

Commissioning an ML implementation is just the first step, as sustainment of these applications requires organizational trust and trained resources. A crucial component of building trust is empowering collaboration among plant personnel. By building this foundation, SMEs can easily reproduce analyses and communicate value generated to management and key stakeholders. Advanced analytics applications play an important role in sustaining ML implementations with out-of-the-box tools for collaboration and communication, including annotations and shared reporting.

ML with no-code multivariate pattern-learning technology. ML applications in industrial environments are reaching a turning point, as users without a background in ML or statistics can now use no-code multivariate pattern-learning technology. This enhanced ML accessibility can lead to increased identification and understanding of complex and valuable patterns among time periods of interest.

To initiate this procedure, users examine cleansed and contextualized multivariate operational data, calling out conditions for the ML application to look for, such as leading indicators of failure, quality deviations and specific plant operating states. As the model works (providing status reports and making process recommendations), users provide feedback on the results, enabling improvement over time through multiple iterations (FIG. 1).

Identified periods of interest can be viewed as capsules used for near-real-time monitoring and diagnostics of industrial processes, enabling SMEs to identify problem sources quickly, thereby accelerating troubleshooting efforts. As learning takes place, these ML applications are highly scalable because a model built on a single asset can be used to initialize monitoring of other similar assets.

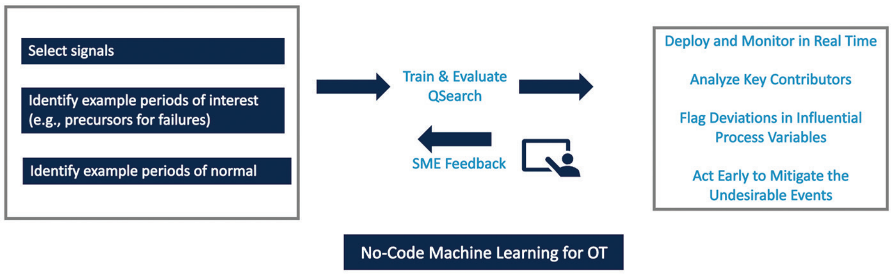

FIG. 1. A no-code ML proprietary application[a] incorporates a workflow that can be used by SMEs to create models and identify periods of interest, regardless of the SMEs' backgrounds in ML or statistics.

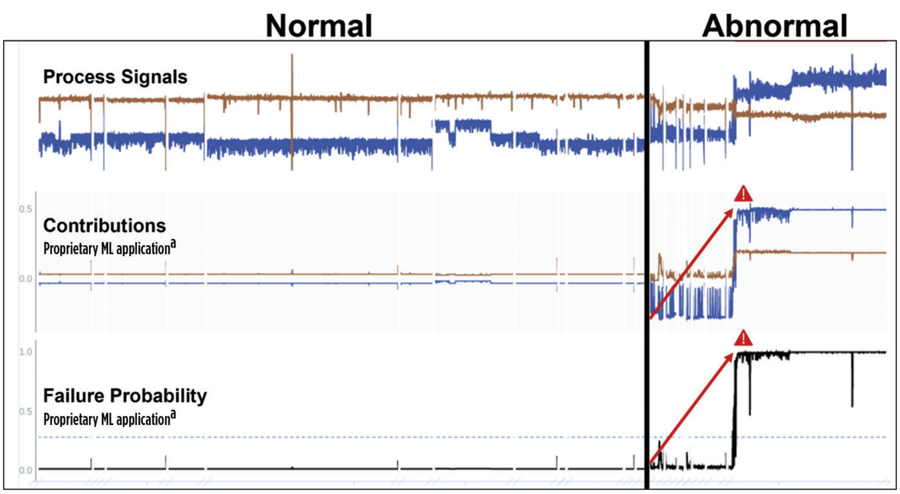

FIG. 2. An oil and gas operator used a proprietary ML application[a] to automatically identify and mitigate abnormal operating conditions, thus reducing failure rates of oil export pumps.

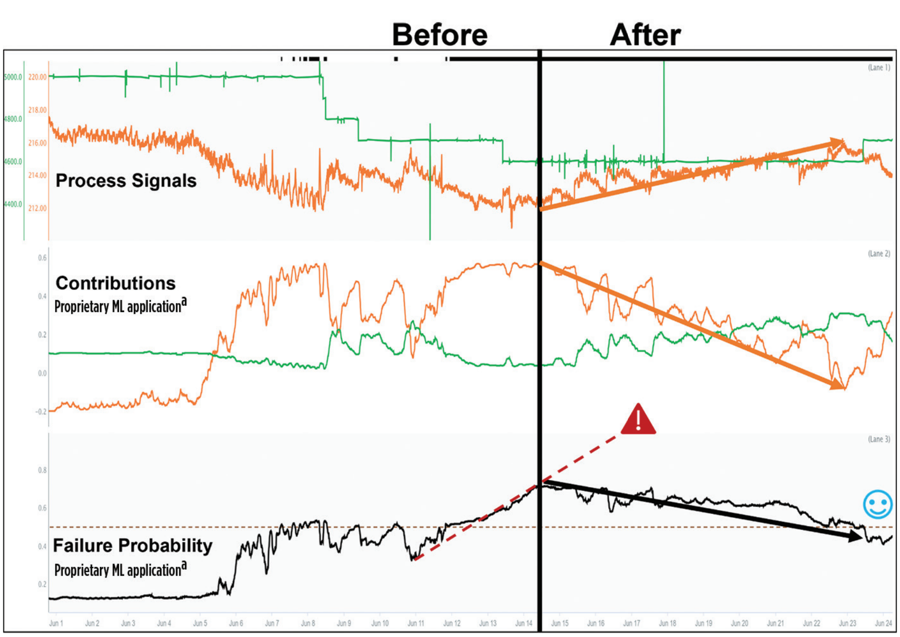

FIG. 3. The proprietary ML application[a] identified a factor increasing the likelihood of failure in an allnex product development campaign. By adjusting this parameter, the team saw significant savings.

Real-world results. By empowering process experts to capitalize on their strengths, increased value can be driven at an industry level, as demonstrated by the following two case studies.

Building operational technology (OT) friendly asset monitoring models in the North Sea. In the oil and gas industry, maintaining and maximizing the lifetime of critical assets—including pumps, valves, heat exchangers and compressors—are vital to profitable operation. Although this example is for upstream operations, similar principles apply for downstream plants and facilities, as they use much of the same equipment.

The failure of oil export pumps can lead to a facility-wide shutdown, and repairs of this highly specialized equipment can be costly and lengthy in duration. Without a proactive condition-based maintenance program in place, plant personnel run the risk of unplanned shutdowns, reduced production, and environmental and safety issues—leaving facilities vulnerable.

To monitor its pumps of this type, Ithaca Energy, an oil and gas operator, implemented a proprietary ML application[a], building an ML model and using the cleansed process instrumentation tags identified as relevant by a process expert. Next, the company leaned on historic examples of unplanned downtime events and normal operation within the application to establish baseline and abnormal conditions for the ML application to use in this analysis.

After letting the model run through several iterations, users reviewed results of the application's condition detection. It was determined that the model correctly identified precursors and signal contributors for past downtime events, so Ithaca commissioned the application to run in near real time, utilizing current operational data to assess the risk of future failure. Built-in online diagnostics were instructive for understanding key contributors to pump failures, and for directing further investigative and troubleshooting efforts (**FIG. 2**).

With proactive monitoring and diagnostics in place, Ithaca Energy improved reliability and uptime, avoiding losses of up to $2 MM/d. Additionally, these diagnostic insights provided a clearer understanding of the root causes for diminished or degraded performance, enabling maintenance personnel to proactively service equipment prior to failure, and to also save time and money. By using the proprietary ML application's[a] asset swapping capability, Ithaca Energy was also able to scale the application to monitor similar assets throughout the enterprise.

Promoting data-driven operational decisions. Manufacturing campaigns for a high-value—but difficult to produce—product at allnex (an industrial coating resins and additives producer) can last from weeks to months. Because of the inherent process complexity and its detrimental impact on processing equipment, each campaign will ultimately end due to the cumulative impact of this harsh process. Extending a campaign can be achieved by lessening the daily harsh conditions that confront equipment—and extending campaigns by even 1 d–2 d can provide significant financial upside.

By implementing the proprietary ML application[a], allnex incorporated timely assessments and insights into product development campaigns, promoting data-driven discussions and interventions to increase success rates. **FIG. 3** shows an instance in which the ML application identified a factor that was increasing the likelihood of campaign failure. By adjusting this process parameter, the team prevented an early failure, resulting in significant savings.

This early warning preceding failure, along with insight into other key contributing factors, empowered operations personnel to act early and get the campaign back on track.

ML improves efficiency.

Industrial ML implementations require process expertise, data, context and collaboration to initialize, but no-code options alleviate the need for extensive ML or statistics understanding.

With the right connectivity and feedback loops, advanced analytics applications are empowering process manufacturers in the use of ML to achieve target key performance indicators, and to preemptively alert operations and maintenance staff when anomalies are detected. These measures provide increased operational efficiency, enable optimal and timely maintenance, and improve enterprise safety and the bottom line. HP

NOTE

[a] Seeq's QSearch

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JIM MARTIN heads the Operational Excellence Group at allnex. The group assists allnex's plants in decreasing energy consumption, reducing waste generation, improving asset reliability, increasing non-capital production capacity, and expanding into the world of digitalization. He has worked for more than 25 yr in both direct manufacturing roles and manufacturing support roles. Martin earned a Bch degree in chemical engineering from Rensselaer Polytechnic Institute, and an MBA degree from Carnegie Mellon University.

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Safeguarding the world's energy

For the foreseeable future, our global economy will continue to rely on fossil fuels as our primary energy source. Because this affects every aspect of the supply chain, the oil and gas sector will continue to be a target for cyber attacks from state and non-state actors that are looking to cripple infrastructure, hold systems for ransom or infiltrate to gain access to new technologies. Although the industry is aware of these escalating threats, much can still be done to increase the safety and security of cyber operations in the global oil and gas industry.

Why is the energy industry prepared for physical threats but not cyber? Most facilities know how to handle physical emergencies. Physical events threaten the safety and well-being of workers and the environment, pushing organizations to have clear procedures for shutting down and opening operations. However, despite cyber attacks having real-world consequences, do these facilities have the processes and procedures in place to detect an attack? Yes and no. Although some companies have robust operational technology (OT) and cybersecurity programs in place, many just meet the minimum criteria of the industry's guidelines and regulations. However, being compliant is not the same as being secure. For many refineries and petrochemical facilities, the lack of OT cybersecurity could result in huge losses and a ripple effect felt across the supply chain.

A year in review: What we have learned from cyberattacks on critical infrastructure. This type of ripple effect was felt strongly in May 2021 when Colonial Pipeline shut down for 6 d following a cyber attack. The attack originated on the business's information technology (IT) side (in its billing department) but ended up disrupting the OT environment. This resulted in huge losses to the company, including a ransom payment of around $4.4 MM, and directly impacted consumers around the U.S. Five days after the initial shutdown, 16% of gas stations in North Carolina had run out of fuel.[1] Gas prices surged across the country, and even states not connected to the pipeline saw consumers rushing to the pump in a panic to secure gasoline.

Another attack in February 2021 targeted a water treatment plant in Oldsmar, Florida. During this attack, hackers gained access to a computer that controlled the balance of chemicals in the water supply for a town of a little more than 15,000 people. The intruder raised the level of sodium hydroxide in the water to lethal levels. While this attack was caught by the plant operator and no one was hurt, the message was clear—cyber threats on critical infrastructure are more than capable of bridging the IT/OT gap, resulting in a cyber-physical event.

How threat actors penetrate and disrupt the supply chain. Often, malware programs are installed years before they are detected. Night Dragon, one of the first cyber attacks of its kind, targeted 71 different organizations in the U.S. with a specific focus on global oil, energy and petrochemical facilities. The program used relatively simple methods for infiltration and went almost entirely unnoticed until McAfee security began releasing information about it nearly 5 yr later. Industrial organizations and vendors may not be aware of threats already lurking in their systems. Breaches that begin as simple malware programs in IT environments have real-world impacts on OT systems. Organizations should start thinking beyond compliance and implement OT cyber programs that can detect, respond to and mitigate the impacts of these threats to themselves, their suppliers and customers.

Vendors may inadvertently pass on security risks to organizations that build and monitor critical infrastructure, creating new vulnerabilities. As equipment becomes increasingly digitized, the need to update and monitor the software running the physical OT equipment grows. Original equipment manufacturers (OEMs) are retaining a higher level of connectivity with their equipment even after it is installed at a new location. This means monitoring software run by a third party is now an integral part of technology inside an organization's operations. Threat actors are aware of these new vulnerabilities and constantly monitor for new ways to exploit them. The SolarWinds attack in 2019 illustrates how this style of attack happens. The Russian foreign intelligence service allegedly compromised the company's monitoring software.

Taking control: How to manage OT systems and vulnerabilities. Securing critical infrastructure comes down to visibility and control. Do I have visibility into my critical OT systems, and do I have control over them? Securing OT environments differs from IT and requires different approaches with different technologies and skills. IT cyber solutions can break OT systems, leading to operational disruption. Many cybersecurity programs are driven by compliance; however, protecting the nation's critical infrastructure will require private industries to look well beyond government regulation.

In the U.S., 85% of critical infrastructure is run by privately owned companies,[2] and the existing regulatory framework seems to be causing turbulence rather than helping organizations become more secure. The latest U.S. Transportation Security Administration requirements for pipeline cybersecurity have more directives aimed at personal computers than pipeline control systems, leaving companies confused on how

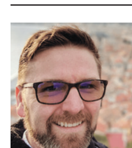
to comply. Between staffing shortages, requirements that are either based on IT systems rather than OT or requirements that cannot be applied across all industrial settings, compliance alone is no longer enough. Companies must take responsibility for protecting the nation's infrastructure by first controlling what they can control. To address the threats of supply chain attacks, offshore platforms, refineries, pipelines and petrochemical facilities can start with a few key actions:

- **Update vendor monitoring processes.** When equipment is installed and monitored remotely, how many people from the OEM have access to it? Organizations must update their processes to account for how authorization is granted to control access to their equipment.
- **Implement passive monitoring systems.** Passive monitoring systems generally utilize mirroring technology to replicate data moving through the system and analyze it for irregularities without communicating with or impacting the data flow through the system. This type of monitoring, when properly implemented, can identify threat actors lurking in IT environments before they bridge the gap to OT and avoids the potential for shutdowns.
- **Keep systems up-to-date.** This is easier said than done. With vulnerabilities appearing daily and software patches emerging monthly, it is nearly impossible to always keep all software fully up-to-date. Furthermore, whenever something is altered in a system's security, it must undergo rigorous testing to ensure new gaps are not opened and industrial control settings are still functioning. In oil and gas environments specifically, shutting down operations for any length of time is not an option, so updates to critical systems must be handled delicately. Allowing equipment to fall out of date and failing to take the necessary time to patch key software vulnerabilities can lead to serious consequences, so these updates must be implemented consistently and carefully.
- **Train staff on best cyber practices.** Many of the most devastating cyber attacks start with human error (e.g., an employee giving away a bit of personal information that allows for a password to be breached or the wrong .exe file being opened and unleashed on a secure system). Ensuring the entire staff is aware of and trained in good cyber practices will go a long way to stopping some of the most accessible access points for threat actors to gain access to your OT environment.
- **Cybersecurity budgetary prioritization.** Refineries, petrochemical facilities and other critical infrastructure sites commonly contain hundreds of millions of dollars in equipment, yet their cybersecurity budget allocation is geared toward compliance and falls well short of what is required to best secure these valuable assets from an attack. According to a recent survey, 47% of industrial control system (ICS) organizations do not have internal dedicated 24/7 ICS security response resources to manage ICS incidents.[4] Refineries and petrochemical facilities must move beyond a compliance-driven mindset and make the business case for protecting their most valuable resources.

Critical infrastructure is being targeted with increasing regularity, and global oil, energy and petrochemical facilities are appealing targets for cyber attackers. The leaders in these industries, including CEOs and executives, have been warned to prepare for an imminent attack focused on disrupting the flow of oil, gas and reliable electricity because of the Russian invasion of Ukraine. Shutting down these sites has widespread effects on organizations, national defense and the economy. In the U.S., it can take regulators years to develop guidelines and rules that address industry needs. Why wait when organizations can implement best practices now? By isolating what can and cannot be controlled in settings like refineries and petrochemical facilities, these industries can protect themselves, their equipment and the lives of their workers.

LITERATURE CITED

Complete literature cited available online at www.HydrocarbonProcessing.com.



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HP Events

OCTOBER

14th International Wire & Cable Trade Fair for Southeast Asia, Oct. 5–7, Bangkok International Trade & Exhibition Centre, Bangkok, Thailand
P: +65 6332-9620
wire@mda.com.sg

5th ME RoTIC, Oct. 11–13,
Dubai, United Arab Emirates
P: +971 4-2790-800
register@aldrichme.com
www.roticmiddleeast.com

***HP* Awards, Oct. 12,**
The Houstonian Hotel, Houston, Texas
Gulf Energy Information Events
(See box for contact information)

AFPM Summit, Oct. 18–20,
Grand Hyatt San Antonio, San Antonio, Texas
(See box for contact information)

Siemens Energy Talks, Oct. 20, Hyatt Regency Houston Galleria, Houston, Texas
Rodrigo.Mondonedo@Siemens-Energy.com
www.siemens-energy.com

AFPM Environmental Conference, Oct. 23–25,
Sheraton New Orleans, New Orleans, Louisiana
(See box for contact details)

Emerson Exchange Americas Conference, Oct. 24–28,
Gaylord Texan Resort & Convention Center, Grapevine, Texas
www.emerson.com

bauma, Oct. 24–30,
Trade Fair Center Messe München, Münich, Germany
P: +49 89-949-11348
Info@bauma.de
bauma.de

NOVEMBER

Women's Global Leadership Conference, Nov. 7–8,
Gulf Energy Information Events
(See box for contact information)

AIChE Annual, Nov. 13–18,
Phoenix Convention Center, Phoenix, Arizona
(See box for contact information)

AVEVA World, Nov. 14–17,
Moscone West Convention Center, San Francisco, California
Events.AVEVA.com
Events@AVEVA.com

API Standard Fall Refining and Equipment Standards Meeting, Nov. 14–18,
Hyatt Regency New Orleans, New Orleans, Louisiana
events.api.org
(See box for contact information)

Valve World Expo, Düsseldorf, Nov. 29–Dec. 1,
Messee Düsseldorf, Düsseldorf, Germany
www.valveworldexpo.com

DECEMBER

15th Annual Aboveground Storage Tank Conference & Trade Show (NISTM), Dec. 6–7, The Woodlands Waterway Marriott, The Woodlands, Texas
P: +1 800-827-3515
mail@nistm.org
www.nistm.org

MARCH 2023

CERAWeek, March 6–10,
Houston Marriott Marquis, Houston, Texas
ceraweek@ihsmarkit.com
www.ceraweek.com

MAY 2023

API Spring Refining & Equipment Standards Meeting, May 15–19,
Hyatt Seattle Washington, Seattle, Washington
(See box for contact information)

API/AFPM Spring Operating Practices Symposium, May 17, Hyatt Seattle Washington, Seattle, Washington
(See box for contact information)

JUNE 2023

Valve World Americas, June 7–8, George R. Brown Convention Center, Houston, Texas
P: +1 416-361-7030
s.bradley@kci-world.com
valveworldexpoamericas.com

NOTE: Due to the COVID-19 pandemic, industry event dates are constantly changing, while others are being postponed indefinitely or canceled. Please consult the appropriate association or organization to confirm event dates, locations and details.

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